BEFORE THE

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

APPLICATION OF DOMINION ENERGY SOUTH CAROLINA, INCORPORATED FOR ADJUSTMENT OF RATES AND CHARGES	)))))	**DOCKET NO. 2020-125-E**

DIRECT TESTIMONY AND EXHIBITS

OF

MARK E. GARRETT

ON BEHALF OF

THE UNITED STATES DEPARTMENT OF DEFENSE AND ALL OTHER FEDERAL EXECUTIVE AGENCIES ("DOD-FEA")

November 10, 2020

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I. WITNESS IDENTIFICATION AND PURPOSE OF TESTIMONY

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Mark E. Garrett. My business address is 4028 Oakdale Farm Circle, Edmond, Oklahoma 73013.

Q: WHAT IS YOUR PRESENT OCCUPATION?

A: I am the President of Garrett Group Consulting, Inc., a firm specializing in public utility regulation, litigation, and consulting services.

Q: WOULD YOU PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND YOUR PROFESSIONAL EXPERIENCE RELATED TO UTILITY REGULATION?

A: I received my bachelor's degree from The University of Oklahoma and completed post graduate hours at Stephen F. Austin State University and the University of Texas at Arlington and Pan American. I received my juris doctorate degree from Oklahoma City University Law School and was admitted to the Oklahoma Bar in 1997. I am a Certified Public Accountant licensed in the States of Texas and Oklahoma with a background in public accounting, private industry, and utility regulation. In public accounting, as a staff auditor for a firm in Dallas, I primarily audited financial institutions in the State of Texas. In private industry, as controller for a mid-sized corporation in Dallas, I managed the company's accounting function, including general ledger, accounts payable, financial reporting, audits, tax returns, budgets, projections, and supervision of accounting personnel. In utility regulation, I served as an auditor in the Public Utility Division of the Oklahoma Corporation Commission ("Commission") from 1991 to 1995. In that position, I managed the audits of major gas and electric utility companies in Oklahoma.

Since leaving the Commission, I have worked on numerous rate cases and other regulatory proceedings on behalf of various consumers, consumer groups, public utility commission staffs and attorney general's offices. My clients primarily include industrial customers, hospitals and hospital groups, universities, municipalities, and large commercial customers. I have also testified on behalf of the commission staff in Utah and the offices of attorneys general in Oklahoma, Washington, Nevada and Florida. I have also served as a presenter at the NARUC subcommittee on Accounting and Finance on the issue of incentive compensation, and as a regular instructor at the New Mexico State University's Center for Public Utilities course on basic utility regulation.

Q: HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS ON UTILITY RATES?

A: Yes. I have provided testimony before the public utility commissions in the states of Alaska, Arizona, Arkansas, Colorado, Florida, Massachusetts, Nevada, Oklahoma, Texas, Utah and Washington. My qualifications were accepted in each of those states. A description of my qualifications and a list of the proceedings in which I have been involved are attached to this testimony as Exhibit No.___(MG-1).

Q: ON WHOSE BEHALF ARE YOU APPEARING IN THESE PROCEEDINGS?

A: I am appearing on behalf of the United States Department of Defense and All Other Federal Executive Agencies ("DOD-FEA").

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A: The purpose of my testimony is to address various revenue requirement and rate design issues identified in the rate case application filed by Dominion Energy South Carolina, Inc. ("DESC" or the "Company"). In this filing, DESC is requesting a $178.234 million increase in rates. In my testimony, I provide recommendations and adjustments to the Company's requested revenue requirement and rate design.

Q: HAVE YOU PREPARED EXHIBITS TO ACCOMPANY YOUR TESTIMONY?

A: Yes. I have prepared Exhibit No.___(MG-1) through Exhibit No.___(MG-5), which are attached to my testimony. These present my findings and recommendations, and include the recommendations and proposed adjustments sponsored by DOD-FEA witness, Dr. Zhen Zhu, who provides testimony regarding cost of capital issues.

Q: TO THE EXTENT THAT YOU DO NOT ADDRESS A SPECIFIC ITEM OR ADJUSTMENT, SHOULD THAT BE CONSTRUED TO MEAN THAT YOU AGREE WITH THE COMPANY'S PROPOSAL FOR THAT ITEM?

A: No. Exclusion from my testimony of any specific adjustments or amounts proposed by DESC does not indicate my approval of those adjustments or amounts, but rather that the scope of my testimony is limited to the specific items addressed herein.

II. REVENUE REQUIREMENT

II. A. SUMMARY OF ADJUSTMENTS

Q: PLEASE PROVIDE A SUMMARY OF THE ADJUSTMENTS PROPOSED IN THIS CASE.

A: A summary of recommendations is set forth below:

Table 1: Summary of Adjustments (Thousands)

Company's Requested Rate Increase	$	178,234
Rate Base Adjustments:		
Storm Reserve Rider		636
Cash Working Capital		(11,517)
Construction Work in Process		(34,401)
Cost of Capital Adjustments:		
Capital Structure		(3,037)
Return on Equity		(42,985)
Operating Income Adjustments:		
Short-Term Incentives		(5,651)
Payroll Tax on Short-Term Incentives		(490)
Long -Term Incentives		(916)
Storm Reserve Rider		(9,840)
Vegetation Management		(3,519)
Turbine Overhaul		(5,009)
Unrecovered Plant Amortization		(10,512)
Critical Infrastructure Protection Costs		(2,380)
Property Related EDIT Amortization		(21,684)
Total Adjustments		(151,306)
Recommended Rate Increase	**$**	**26,926**

II. B. CASH WORKING CAPITAL ADJUSTMENT

Q: HAVE YOU REVIEWED DESC'S PROPOSED CASH WORKING CAPITAL ("CWC") ADJUSTMENT?

A: Yes. DESC is requesting $111 million for cash working capital for the South Carolina retail jurisdiction.[1] DESC's adjustment applies a 45-day lag for all revenues associated with its operating expense accounts. This approach is referred to as the 45-day formula approach or the 1/8th method. The method is calculated by multiplying operating expense account balances by 12.5%, which is 1/8th of a year or 45 days (360/8=45 days). The method assumes that revenues are received, on average, 45 days after expenses are paid. For example, the method assumes that the labor cost needed to produce and deliver electricity is paid 45 days ***before*** customers pay their invoices each month. In other words, the method assumes that ***every*** expense is prepaid by DESC – 45 days before DESC receives payments from its customers.

Q: DO YOU AGREE WITH DESC'S USE OF THE 45-DAY FORMULA?

A: No. The 45-day formula is obsolete and has been abandoned by most public utility commissions. It is based upon assumptions that are no longer valid. It is in the best interest of ratepayers to utilize a method that more closely reflects the cash management practices of modern utilities. I understand, however, that the Commission has previously allowed utilities to use the 45-day formula when there was insufficient evidence to demonstrate the

[1] See Direct Testimony of Keith C. Coffer, Jr., Exhibit No.___(KCC-6), Exhibit C-6, page 2 of 2, line 1.

method yields an inadequate result.

Q: WHAT IS CASH WORKING CAPITAL AND WHY IS IT AN IMPORTANT RATEMAKING ISSUE?

A: The issue of cash working capital at one time was the source of much discussion and controversy in public utility rate proceedings throughout the United States. This controversy existed, in part, because many utilities persisted in making requests to include substantial amounts in rate base for cash working capital long after the modern techniques of cash management had made those requests obsolete.

Cash working capital is often defined as the net outlay of cash that a utility must furnish to provide service before the payment for that service is received from its customers. However, it is more common today for a utility to receive payments from customers ***before*** the various obligations to vendors and employees become due. This creates a situation where the customers are supplying DESC with cost-free capital. In such a situation, a ***reduction*** to rate base is more appropriate than an increase.

A utility's ability to negotiate large contracts advantageously, coupled with its utilization of sound cash management techniques, will in most situations produce a negative cash working capital requirement. In other words, ratepayers pay the utility before the utility pays its employees and vendors. Therefore, commissions should be very circumspect about allowing utilities to include cash working capital allowances in rate base.

Q: HOW DO COMMISSIONS DETERMINE WHETHER RATEPAYERS ARE ACTUALLY SUPPLYING THE UTILITY'S OPERATING CAPITAL?

A: A lead-lag study is the most accurate way to determine whether the utility or its ratepayers are providing the cash that pays the utility's bills. A lead-lag study compares the timing differences between the inflows of cash from revenues and the outflows of cash for operating expenses. The net difference is expressed as a ***positive*** cash requirement if the utility is supplying cash to pay the day-to-day operating expenses before payments for these services arrive from the customers, and as a ***negative*** cash requirement if payments from customers actually arrive before the utility is obligated to pay its various expenses. These differences are expressed in the number of days between the time the utility pays its bills and the time the customers pay the utility.

Q: DO MOST COMMISSIONS USE LEAD-LAG STUDIES TO DETERMINE CASH WORKING CAPITAL NEEDS?

A: Yes. The Garrett Group, LLC conducted a telephone survey of the state regulatory commissions of the 24 Western states to understand how cash working capital requirements are determined in each jurisdiction. A summary of the results of that survey are set forth in the table below:

Table 2: Cash Working Capital Survey[2]
Method for Calculating Cash Working Capital by State

	Lead-Lag Study	Balance Sheet Approach	45-Day Formula (1/8th Method)
Alaska	X[3]		
Arizona	X		
Arkansas		X[4]	
California	X		
Colorado	X		
Hawaii	X		
Idaho	X[5]	X	
Iowa	X		
Kansas	X		
Louisiana			X
Minnesota	X		
Missouri	X		
Montana	X		
Nebraska	X[6]		
Nevada	X		
New Mexico	X		
North Dakota	X		
Oklahoma	X		
Oregon	X		
South Dakota	X		
Texas	X		
Utah	X		
Washington		X	
Wyoming	X[7]		

[2] Source: Garrett Group, LLC, 2011 Survey of the 24 Western States' Cash Working Capital calculation method.

[3] Most utilities in Alaska are cooperatives and municipalities that use some form of debt service coverage approach for revenue requirement, where CWC is not part of the equation. Alaska's largest utility using a rate base rate of return approach to determine revenue requirement, Municipal Light and Power, was allowed the use of the 45-Day method up until the utility's 2013 rate case. In that case ML&P agreed to use a lead lag study approach going forward.

[4] Arkansas uses a unique balance sheet approach because, in that state, CWC is included in the cost of capital calculations whereas other balance sheet items are also included in the cost of capital calculations.

[5] Idaho also will accept the balance sheet approach for computing cash working capital.

[6] Electric customers in Nebraska are served entirely by consumer-owned electric utilities. For gas utilities, Nebraska uses a lead-lag study if a company requests cash working capital.

[7] Wyoming uses lead-lag studies for larger utilities. Smaller companies which cannot afford the costs of a lead-lag study are allowed to use the 45-Day method (or ⅛th of operation and maintenance costs ("O&M")).

Q: WHAT DO THE RESULTS OF THE SURVEY SHOW?

A: The survey shows that nearly every Western state uses a lead-lag study to calculate cash working capital. Only three states use other methods. Arkansas uses a balance sheet approach, but is unique in that it includes the cash working capital calculation as a part of the cost of capital determination, along with other non-plant balance sheet accounts, such as deferred income taxes and customer deposits. Washington uses a balance sheet approach, Idaho *allows* a balance sheet approach, only Louisiana uses a 45-day formula.

Q: WHAT IS THE CRITICISM OF USING A LEAD-LAG STUDY?

A: Some utilities complain that a lead-lag study is expensive to perform.

Q: IS THIS A VALID CRITICISM?

A: No. A ***comprehensive*** lead-lag study can be performed for $50,000 to $75,000, and possibly even less for a utility the size of DESC. A lead-lag study only needs to be performed every three to five years for ratemaking purposes. That means, for approximately $15,000 per year a utility can accurately present its cash working capital requirements. In the case of DESC, the utility is requesting $111 million in rate base for cash working capital, which translates into $11.5 million in rates each year.[8] From the ratepayers' perspective, a $15,000 investment to avoid charges of $11.5 million per year is money well spent.

[8] See Exhibit No. ___(MG-2, line 4).

Q: IF A UTILITY DOES NOT PERFORM A LEAD-LAG STUDY, HOW SHOULD THE CASH WORKING CAPITAL REQUIREMENT BE SET IN A RATE CASE?

A: Without a lead-lag study, the cash working capital requirement should be ***set at zero***. This is required in several states. Texas takes the zero cash working capital assumption even further. Texas regulations require that the cash working capital requirement be set at a ***negative*** 45-days for a utility that fails to provide a valid lead-lag study. The assumption in Texas is that a well-run utility should have a negative cash working capital requirement with the technology and cash management techniques available today.

Q: IS THE ASSUMPTION THAT CASH WORKING CAPITAL IS GENERALLY NEGATIVE A VALID ASSUMPTION IN YOUR EXPERIENCE?

A: Yes. A financially healthy utility will almost always have a negative cash working capital requirement. The only utility I can recall having a positive cash working capital requirement in recent years was Nevada Power Company, and this was during a period of severe financial distress, when that company was below investment grade. [9]

Q: WOULD IT BE UNUSUAL FOR A UTILITY TO HAVE A POSITIVE 45-DAY CASH WORKING CAPITAL REQUIREMENT?

A: Yes. It would be very unusual for a utility to have a positive 45-day cash requirement. If

[9] Nevada Power Company ("NPC") had positive cash working capital balance when it was in junk-bond status after a half-billion dollar disallowance for imprudent fuel and purchased power expenditures. NPC's credit ratings at that time were so low that vendors required prepayments for goods and services before delivery. Once NPC's financial performance and credit ratings improved, its cash working capital balance again became negative, as is the case with the majority of utility companies.

a utility were in bankruptcy and the receiver was paying all goods and service in advance, the positive cash requirement could approach 45 days, but it is hard to imagine even in that situation that it would reach a full 45-days. The 45-day approach assumes that all expenses are ***prepaid.*** This would almost never be the case. A 45-day revenue lag is certainly not an accurate reflection of the current financial practices or the cash working capital requirement of DESC, or any utility for that matter. The table below shows a list of rate cases in which I was a witness reviewing the CWC issues. It shows that utilities typically have a ***negative,*** rather than positive, cash working capital balance.

Table 3: Summary of Treatment of Cash Working Capital Issues

Company and Proceeding	CWC Balance (Neg., Pos., Zero)
Nevada Power Company, 2020 (Docket No. 20-06003)	Negative
Oklahoma Gas and Electric Co., 2018 (Cause No. PUD 18-00140)	Negative
Sierra Pacific Power Company, 2013 (Docket No. 13-06002)	Negative
Nevada Power Company, 2011 (Docket No. 11-06006)	Negative
Southwestern Electric Power Company, 2012 (PUC Docket No. 40443)	Negative
Entergy Gulf States, 2008 (PUC Docket No. 34800)	Negative
Public Service Company of Oklahoma, 2010 (Cause No. PUD 10-50)	Negative
Public Service Company of Oklahoma, 2006 (Cause No. PUD 06-285)	Negative
Nevada Power Company, 2006 (Docket No. 06-11022)	Positive[10]
Atmos Energy Corp., Mid-Tex Division, 2006 (Texas GUD 9676)	Negative
Oklahoma Gas and Electric Co., 2005 (Cause No. PUD 05-151)	Negative
Oklahoma Natural Gas Co., 2005 (Cause No. PUD 04-610)	Zero (in Lieu of Lead/Lag)
Public Service Company of Oklahoma, 2003 (Cause No. PUD 03-0076)	Negative
Nevada Power Company, 2002 (Docket No. 01-10001)	Zero (in Lieu of Lead/Lag)
Public Service Company of Oklahoma, 1997 (Cause No. PUD 96-0214)	Negative
Oklahoma Natural Gas Company, 1992 -1993 (Cause No. PUD 92-1190)	Negative
Oklahoma Gas and Electric Company, 1991-1992 (Cause No. PUD 91-1055)	Zero (in Lieu of Lead/Lag)

[10] Nevada Power Company was below investment grade at this time after a $500+ million fuel and purchased power imprudence disallowance.

Q: WHAT DO YOU RECOMMEND?

A: I recommend that the Commission adopt the policy applied in many states—that a lead-lag study is essential if a positive cash working capital requirement is requested. Without a lead-lag study, the cash3 working capital should be set at zero, because a well-run utility should have a negative balance.

In my opinion, DESC will experience no financial harm if it stops relying on ratepayers for a cash working capital requirement that does not exist. This adjustment in the amount of $111 million to remove DESC's CWC adjustment from rate base is set forth in Exhibit No.___(MG-2).

II. C. PROPERTY-RELATED UNPROTECTED EDIT AMORTIZATION

Q: PLEASE DESCRIBE YOUR EXPERIENCE WITH RATEMAKING ISSUES RELATED TO THE TAX CUTS AND JOBS ACT OF 2017 ("TCJA").

A: I have testified and/or consulted in numerous cases involving implementation of the TCJA. These cases include, but are not limited to, the following utilities:

a. Avista Corporation d/b/a Avista Utilities ("Avista"),
b. Atmos Energy Corp., Mid-Tex Division ("Atmos Mid-Tex"),
c. Atmos Pipeline—Texas ("APT"),
d. CenterPoint Energy Houston Electric ("CEHE"),
e. El Paso Electric Company, Texas ("EPE-TX")
f. El Paso Electric Company, Texas ("EPE-NM")
g. Empire District Electric Company ("Empire"),
h. Nevada Power Company ("NPC")

i. Oklahoma Gas & Electric Company ("OG&E"),
j. Oncor Electric Company ("Oncor"),
k. Public Service Company of Oklahoma ("AEP-PSO"),
l. Sierra Pacific Power Company ("SPPC")
m. Southwest Gas ("SWG")
n. Southwestern Public Service Company ("SPS"),
o. Texas Gas Service ("TGS"),
p. Aqua Utilities Inc. ("Aqua Texas")
q. CenterPoint Energy Houston, LLC ("CenterPoint Energy")
r. Puget Sound Electric ("PSE")

Q: WHAT IS THE ISSUE REGARDING PROPERTY-RELATED EXCESS DEFERRED INCOME TAX AMORTIZATION IN THIS CASE?

A: The TCJA reduced the corporate tax rate from 35% to 21%. As a result of the TCJA, utilities that had collected taxes from ratepayers at the higher (35%) corporate tax rate were in possession of over-collected taxes (paid by ratepayers) that the utilities would not be required to remit to any taxing authority. Therefore, the TCJA provided specific rules for the return of these excess deferred income taxes ("EDIT") to ratepayers. The TCJA rules specify the manner and timing in which this should occur, for both protected and unprotected EDIT. ***Protected*** EDIT must be given back to ratepayers over a period of time prescribed by the IRS, and ***unprotected*** EDIT can be given back to ratepayers over any period of time prescribed by the state commission.

The issue in this case relates to the timing of returning ***unprotected*** EDIT to ratepayers. In its final order approving the 2019 merger of Dominion Energy, Inc. and

South Carolina Gas & Electric ("SCG&E"), the Commission explained that Federal law governs the timing of returning EDIT resulting from the TCJA's reduction in the corporate income tax rate ("protected EDIT") to ratepayers.[11]

> Specifically, protected EDIT may not be returned to customers any faster than allowed by the Average Rate Assumption Method ("ARAM"). However, the timing of the distribution of the remainder of the EDIT ("unprotected EDIT") is not similarly constrained by the tax law. ORS proposes returning the entirety of plant-related ***unprotected*** EDIT over a five-year period in the Tax Savings Rider; the Joint Applicants propose returning the unprotected EDIT over the remaining book life of the property generally in accordance with the ARAM, which, the joint applicants assert, tracks and provides symmetry between the reductions in plant-related EDIT with the period of depreciation of the underlying assets to which the EDIT relates. (emphasis added)[12]

Q: HOW DID THE COMMISSION DECIDE THIS ISSUE IN THE MERGER DOCKET?

A: The Commission agreed with the Joint Applicants. The Commission stated:

> The Commission agrees with the Joint Applicants' approach for several reasons. First, the ORS approach would create a significant mismatch between the amortization of the unprotected EDIT and the actual depreciation of the related assets. Second, the five-year amortization period would (in isolation) result in the potential for an increase in customer rates in year six. Third, we find that applying the ARAM method to both protected and unprotected plant-related EDIT results in uniformity, ease of administration, and sound regulatory economics including providing intergenerational equity and rate stability to current and future customers. Accordingly, the return of both protected and unprotected plant-related EDIT should be calculated using ARAM, as proposed in Plan–B Levelized.[13]

[11] *See* Docket Nos. 2017-207-E, 2017-305-E, and 2017-370-E – Order No. 2018-804, December 21, 2018, at page 53.
[12] *Id.*
[13] *See* Docket Nos. 2017-207-E, 2017-305-E, and 2017-370-E – Order No. 2018-804, December 21, 2018, at page 54.

Q: WHAT DO YOU RECOMMEND?

A: I recommend that the Commission order the Company to begin returning the property-related ***unprotected*** EDIT to ratepayers more quickly than previously authorized in the merger docket. The unprotected EDIT is ratepayer money that must be returned to ratepayers. The utility should not be allowed to retain these ratepayer funds for any extended length of time since the TCJA rules allow the immediate return of unprotected EDIT to ratepayers. A timely return of the ratepayers' overpaid taxes is the appropriate treatment from a policy perspective, and especially important under current economic conditions.

Since the date of the Commission's last order in the merger docket, the economic situation has changed dramatically. As a result, I recommend that the Commission's treatment of this issue be revised going forward. The COVID-19 pandemic is causing many customers to experience significant financial distress. I believe the Commission should look for reasonable opportunities to alleviate this burden. In particular, the Commission can take steps, such as the one recommended here, which alleviate the burden on ratepayers without harming the Company in any way. For example, all of the adjustments to lengthen the recovery periods for regulatory assets provide significant rate relief to customers now, when they need it, without causing any financial harm to the Company. Likewise, shortening the period for regulatory liability refunds, such as EDIT reimbursements, will provide rate relief to customers without harming the Company.

Q: DOES THE RATIONALE FOR AMORTIZING THE UNPROTECTED PLANT-RELATED EDIT OVER THE ARAM PERIOD OVERCOME THE EXIGENCY OF THE CURRENT ECONOMIC DOWNTURN FOR RATEPAYERS?

A: No. The first rationale – that the ORS approach would create a significant mismatch between the amortization of the unprotected EDIT and the actual depreciation of the related assets – ***is not as important*** as providing rate relief as soon as possible to customers who are either unemployed of under-employed or business owners with shuttered businesses. These customers need relief now, not 50 years from now. Moreover, there is a significant portion of ADIT related to these assets that will be paid out over the life of the assets; that portion is all of the ADIT that is not excess ADIT, in other words, the 60% of the original ADIT that did not become excess ADIT with the reduction in tax rates to 21%.[14] That portion of ADIT will still track the useful lives of the assets—and that is sufficient. If the tax law intended for unprotected plant-related ADIT to be returned over the life of the underlying assets it would have designated this property-related EDIT as protected rather than unprotected. The fact that the EDIT is ***unprotected*** means that it no longer needs to track the depreciable life of the underlying plant.

Q: WHAT ABOUT THE SECOND RATIONALE?

A: The second rationale – that the five-year amortization period would (in isolation) result in

[14] 21% / 35% = 60%.

the potential for an increase in customer rates in year six– is compelling but not sufficiently compelling in this environment to delay rate relief that is so needed at this time.

Q: CAN YOU ADDRESS THE THIRD RATIONALE?

A: Yes. The third rationale—that applying the ARAM method to both protected and unprotected plant-related EDIT results in uniformity, ease of administration, and sound regulatory economics including providing intergenerational equity and rate stability to current and future customers—is not a compelling reason to delay returning unprotected EDIT to ratepayers. The uniformity that should be achieved is to treat all unprotected EDIT alike. More importantly, though, is that there is no intergenerational equity that needs to be achieved for *future* ratepayers. *All* of the EDIT was paid by *past* ratepayers and future ratepayers are not entitled to any of the EDIT refunds. That is precisely why the unprotected EDIT should be refunded to ratepayers as soon as practicably possible. This provides the best chance of getting the overpaid taxes back to the ratepayers that overpaid them.

Q: HAVE YOU BEEN INVOLVED IN CASES WHERE THE UNPROTECTED EDIT IS GIVEN BACK TO RATEPAYERS OVER A VERY SHORT TIME PERIOD?

A: Yes. In the current Nevada Power rate case, the Public Utility Commission of Nevada accepted an agreement of the parties to refund all remaining unprotected EDIT, in the amount of $26 million, through a one-time bill credit, in other words, an immediate refund.[15]

Q: WERE YOU INVOLVED IN OTHER CASES WHERE THE UNPROTECTED EDIT WAS GIVEN BACK TO RATEPAYERS OVER A SHORTER TIME PERIOD?

A: Yes. In the Entergy Texas 2018 rate case, the parties agreed to refund $185.2 million of unprotected EDIT over a 12-month period for commercial customers (Large General and General rate classes) and over a 4-year period for all other classes.[16]

Q: WHAT DO YOU RECOMMEND?

A: I recommend that the Commission order DESC to refund to ratepayers all the property-related EDIT over a 5-year period.

Q: WHAT IS THE AMOUNT OF THIS ADJUSTMENT?

A: The adjustment in the amount of $21.684 million is set forth at Exhibit No. ___(MG-2).

II. D. ANNUAL INCENTIVE COMPENSATION ("AIP") ADJUSTMENT

Q: PLEASE PROVIDE A BRIEF DESCRIPTION OF DESC'S ANNUAL INCENTIVE COMPENSATION PLANS.

A: DESC's annual incentive compensation plans are formal written plans approved by senior management. In this application, DESC seeks to include incentive compensation accrued

[15] See Public Utility Commission of Nevada, Docket No. 20-06003, Interim Order No. 2.
[16] See Public Utility Commission of Texas, Final Order and Stipulation in Docket No. 48371.

for employees of both DESC and Dominion Energy Southeast Services, Inc. ("DESS").[17] DESS is a services company consisting of legacy SCANA employees and providing corporate support to DESC and other legacy SCANA businesses. DESS functions include information technology, accounting, finance, human resources, legal, procurement, and other areas. [18] Company witness Elbert explained how the legacy annual incentive programs changed during the 2019 test year.

> Accordingly, during the test period, we preserved the pre-merger target award percentages and applied them as they existed at the time of the merger to legacy employees. In addition, for 2019, we also preserved the ability of the top 15% of performers in the former 3-5-7 plan tiers to earn an additional 3%, 4%, or 5% based on their target tier. ***However, we made other aspects of the annual incentive compensation comply with the structure of Dominion Energy's company-wide AIP, including the funding provisions and goals***.[19]

Q: BY MAKING DESC'S PLANS COMPLY WITH DOMINION ENERGY'S COMPANY-WIDE AIP, IS THE FUNDING OF DESC'S AIP NOW DIRECTLY TIED TO THE CONSOLIDATED FINANCIAL RESULTS OF THE PARENT COMPANY, DOMINION ENERGY?

A: Yes. According to Ms. Elbert,

> The Dominion Energy board-level Compensation, Governance, and Nominating Committee ("CGN Committee") is responsible for determining plan funding.[20] In making its determination, the CGN Committee considers Dominion Energy's financial performance. Each year, the CGN Committee sets a financial target for 100% plan funding based on operating earnings per share ("EPS"). For 2019, that target was $4.20 operating EPS.[21]

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[17] Direct Testimony of Regina J. Elbert, p. 2, lines17-19.
[18] Direct Testimony of Regina J. Elbert, pp. 2-3, n. 1.
[19] Direct Testimony of Regina J. Elbert, p. 10, lines 9-15. (Emphasis added).
[20] Direct Testimony of Regina J. Elbert, p. 11, lines 15-17.
[21] *Id.*, p. 11, lines 17-20.

Q: FROM YOUR REVIEW, DO FINANCIAL PERFORMANCE MEASURES COMPRISE A SIGNIFICANT COMPONENT OF THE INCENTIVE COMPENSATION METRICS?

A: Yes. The Dominion Energy 2019 AIP attached to Ms. Elbert's testimony as Exhibit___(RJE-1) indicates the plan is heavily dependent on financial performance measures. First, as stated above, the funding for the AIP is determined based entirely on Dominion Energy's earnings per share (EPS). In addition, the plan also has a minimum funding ***trigger*** so that if Dominion Energy's minimum EPS target is not met, ***the plan would not be funded***. In other words, even though other performance goals for individual contributors include both financial and operational measures, the actual funding of the AIP is tied to financial performance, and the *funding* trigger is directly tied to financial performance. The 2019 AIP Funding Mechanism specifically states:

> The AIP funding mechanism is based on Dominion Energy's consolidated operating earnings per share (EPS) with a minimum funding EPS threshold and maximum funding %.[22]

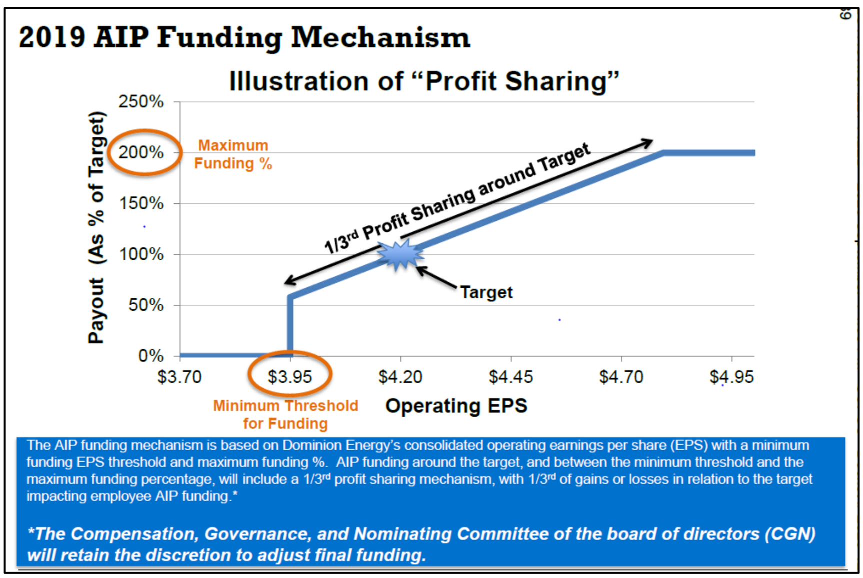
Thus, regardless of how well the employees may perform in non-financial or operational performance measures such as safety or customer satisfaction, if Dominion Energy's EPS is below the minimum threshold for funding, the AIP would be 0%. In this scenario, the Company would simply keep all of the money provided by ratepayers for incentive costs. Dominion Energy's EPS is the primary controlling factor in determining whether: (1) the

[22] See Direct Testimony of Regina J. Elbert, p. 3, Exhibit___(RJE-1), described as the PowerPoint presentation that the Company used to explain the 2019 AIP to its employees.

incentive compensation will be paid, and (2) to what extent.

Q: HOW DOES THIS FUNDING MECHANISM WORK?

A: Dominion Energy's 2019 AIP has an EPS funding trigger (minimum threshold) of $3.95. Moreover, the plan provides for ***increasing*** levels of funding for employee incentives based on the achievement of ***higher*** earnings levels. The plan states that if Dominion Energy achieves a target consolidated operating EPS of $4.20, the funding would be 100%. At a consolidated operating EPS of $4.75, the funding level would be 200%, as shown in the chart below, excerpted from the Dominion Energy's company-wide plan:[23]



This shows that if EPS is less than the 'Minimum Threshold for Funding' of $3.95, the Dominion Energy CGN Committee, in its discretion, would decline funding for that year and there would be no incentive payments. In that event, employees would receive no incentive compensation payout, regardless of how well they scored on operational

[23] See Direct Testimony of Regina J. Elbert, p.37, Exhibit___(RJE-1).

performance measures, and any amount included in rates would be retained for the benefit of Dominion Energy's shareholders.

Q: IS THERE ADDITIONAL EVIDENCE THE FUNDING OF DOMINION ENERGY'S AIP DISCRETIONARY AND CONTINGENT ON FINANCIAL PERFORMANCE?

A: Yes. The CGN Committee retains final discretion to determine the plan funding levels.[24] Specifically, the Dominion Energy 2019 AIP presentation at Exhibit No. ___(RJE-1) makes the following statements:

> The Compensation Governance and Nominating (CGN) Committee has the ***discretion to reduce or eliminate payout*** based on performance;[25]
>
> The Compensation Governance and Nominating Committee of the board of directors (CGN) ***will retain the discretion*** to adjust final funding.[26]

Q: DO INCENTIVE PLANS OF THIS NATURE PRIORITIZE THE INTERESTS OF SHAREHOLDERS OVER THE INTERESTS OF CUSTOMERS?

A: Yes. Plans that are heavily weighted on EPS targets, especially those that have an EPS trigger and an EPS funding mechanism, clearly prioritize shareholders' earnings. Such plans are designed to place shareholders' interests first—that is, to ensure that the parent company achieves targeted shareholder earnings levels ***before*** utility employees are paid any incentive compensation. Such payments remain in the ***discretion*** of parent company management. From a ratemaking perspective, this means that money collected from

[24] Direct Testimony of Regina J. Elbert, p.13, lines 2-3.
[25] Direct Testimony of Regina J. Elbert, p.30, Exhibit___ (RJE-1) (Emphasis added).
[26] Direct Testimony of Regina J. Elbert, p.37, Exhibit ___(RJE-1) (Emphasis added).

ratepayers for the purpose of paying utility employee incentives may or may not be paid to employees, but instead may be diverted, if needed, to bolster parent company shareholders' return on investment.

Q: ARE THERE INDICATIONS THAT THE PLAN IS HEAVILY WEIGHTED ON FINANCIAL PERFORMANCE?

A: Yes. In addition to: (1) the EPS minimum funding threshold (trigger) and (2) the escalating payout percentage tied to Dominion Energy's consolidated financial performance, the specific goals within the plan also create strong incentives all employees, especially management, to focus on financial goals, as shown in the chart below: [27]

2019 AIP Goal Plan Points

	Consolidated Financial Goals		Business Unit Financials	Operating & Stewardship: Safety		Diversity & Inclusion	Environmental	Up to 4 Add'l Goals		Total O/S Points		Total (Maximum) Overall Goal Points
CEO	85 pts	+	n/a	5 pts	n/a	5 pts	5 pts	0 pts	+	15 pts	=	100 pts
EVP/ BU CEO	40 pts	+	45 pts	5 pts	n/a	5 pts	5 pts	0 pts	+	15 pts	=	100 pts
SVP/ VP	15 pts	+	35 pts	10 pts minimum	+ 5 pts	10 pts minimum	10 pts minimum	20 pts	+	50 pts	=	100 pts
Leadership (Non-executive)	n/a	+	35 pts	10 pts minimum	+ 5 pts	10 pts minimum	10 pts minimum	35 pts	+	65 pts	=	100 pts
Individual Contributors	n/a	+	25 pts	10 pts minimum	+ 5 pts	10 pts minimum	10 pts minimum	45 pts	+	75 pts	=	100 pts

This chart shows the weighting of the 2019 AIP goals for various company-wide positions. The first two rows indicate that Dominion Energy's CEO, EVP, and other top-level management have goals based 85% on financial performance measures, and only 15% on

[27] Direct Testimony of Regina J. Elbert, p.38, excerpt from Exhibit___ (RJE-1).

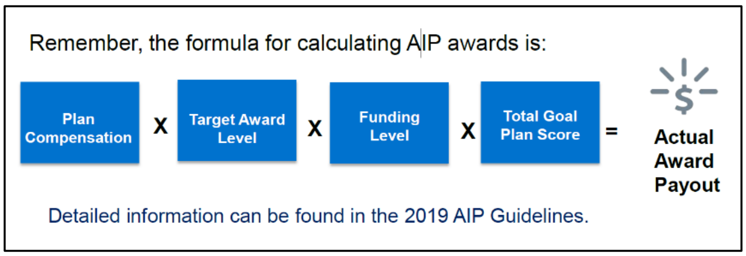
operational measures. On the third row of the chart it shows that for SVP/VP level employees the goals are weighted 50% financial and 50% operational. On the fourth row it shows that non-executive leadership position goals are weighted 35% on business unit financial performance. Finally, the last row of the chart indicates that all individual contributors' goals are weighted at least 25% on business unit financial performance.

Q: WHAT DOES THIS WEIGHTING OF THE 2019 AIP PERFORMANCE GOALS INDICATE?

A: First, it is important to recognize that a meaningful portion of the incentive compensation of ***every*** participant in the 2019 AIP plan is directly tied to financial performance measures. The degree to which the financial goals impact compensation increases progressively. It is highest for Dominion Energy's management positions. This means that decisionmakers in the highest-level positions are afforded disproportionate incentives to maximize shareholder earnings ahead of operational goals. In practice, this element of the plan likely has a trickle-down effect. For those in Dominion Energy's upper management to achieve their incentive compensation, the targeted financial goals must be prioritized whether or not the achievement of financial targets are weighted as heavily for utility employees.

Q: IF THE AIP GOALS NON-LEADERSHIP POSITIONS ARE WEIGHTED 25% FINANCIALLY-BASED, DOES THIS MEAN THAT <u>OVERALL PLAN METRICS</u> FOR THESE EMPLOYEES ARE ONLY 25% FINANCIALLY-BASED?

A: No, even for individual contributors in non-leadership positions, the composite financially-based performance measures are much higher than the stated 25% financial metric. This is because the "actual award payout" for an individual employee is *not* based solely on the stated performance goals for that position. Instead, as discussed in the section above, the actual award payout is *limited* by Dominion Energy's consolidated EPS funding level trigger and *multiplied* by its escalating EPS target award levels. The formula for the actual award payout is shown in Dominion Energy's AIP presentation, as follows:[28]



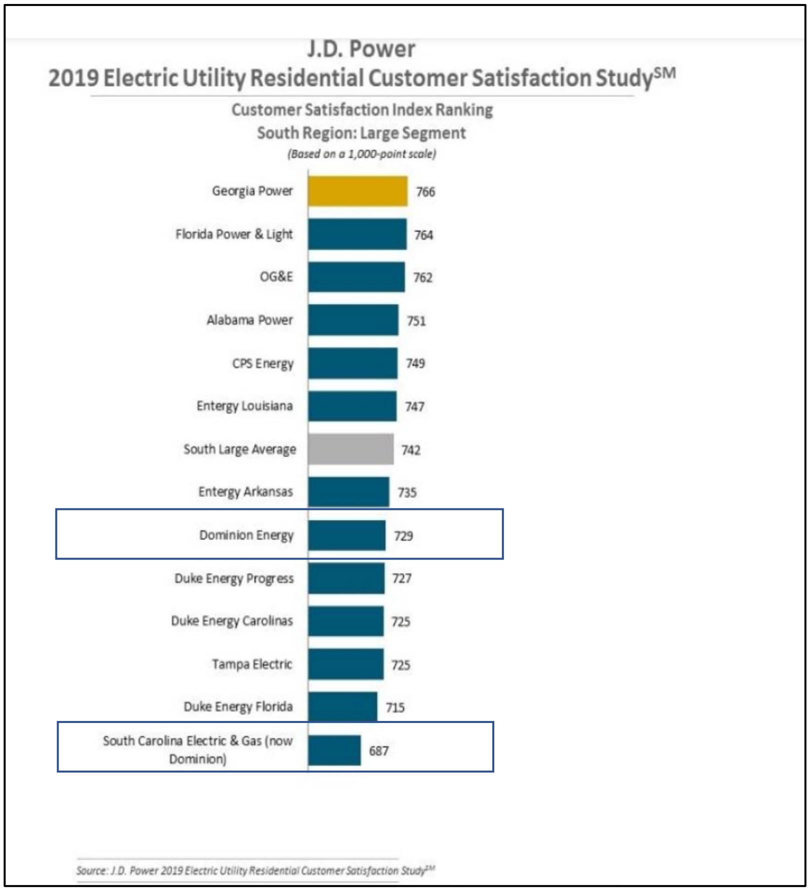
According to this formula, an employee's Total Goal Plan Score is just one component of the actual award payout. Thus, although an employee's Total Goal Plan Score may be weighted 25% financial and 75% operational, the composite formula above results in a ***much higher financial weighting*** because the "Funding Level" multiplier is based solely on financial performance.

Q: IS THERE INDEPENDENT EVIDENCE ON HOW THE COMPANY IS PERFORMING WITH RESPECT TO CUSTOMER SERVICE MEASURES?

A: Yes. The 2019 J.D. Power Residential Overall Customer Satisfaction Index ranks both Dominion Energy and South Carolina Electric & Gas (now Dominion), and it reveals ***below average rankings*** in customer satisfaction compared to other utilities in its segment.

[28] Direct Testimony of Regina J. Elbert, p.39, excerpted from Exhibit___ (RJE-1).

As shown in the chart below, Dominion Energy ranked 'below average' in the South Region: Large Segment. Moreover, South Carolina Electric and Gas (now Dominion) ranked ***the lowest*** in customer satisfaction in its category:[29]



It is interesting that DESC's AIP award for 2019 was above-target (110%) when objective customer satisfaction rankings were so unfavorable. Ms. Elbert explains,

> The actual AIP award for that plan year was made at approximately 110% of target ***due to favorable funding from the Dominion Energy level***. A pro forma adjustment has reduced the AIP test year expense to 100% for purposes of this rate proceeding. [30]

[29] Source: J.D. Power 2019 Electric Utility Residential Customer Satisfaction Study. The J.D. Power 2019 Electric Utility Business Customer Satisfaction Study also ranked Dominion Energy as below average.
[30] Direct Testimony of Regina J. Elbert, p.3, lines 11-14. (Emphasis added).

In other words, the favorable funding from the Dominion Energy (based on financial metrics) caused DESC to receive an above-target incentive compensation payout ***despite*** unfavorable customer satisfaction rankings.

Q: HOW HAS THIS COMMISSION PREVIOUSLY ADDRESSED THE ISSUE OF SHORT TERM INCENTIVE COMPENSATION?

A: The Commission addressed incentive compensation for South Carolina Electric & Gas ("SCE&G") in Docket 2012-218-E. In its Order the Commission stated:

> In previous dockets, the Commission approved the inclusion of 50% of incentive in rates finding that this level of inclusion resulted in a "reasonable pay package" for SCE&G. *See*, Order 1996-15. In a later proceeding, the Commission ruled that a ***"50/50 sharing between shareholders and ratepayers of the costs for employee and executive bonuses creates a reasonable incentive to create ratepayer benefit***." See, Order No. 2005-2. We followed this reasoning again as recently as the 2011 electric rate order for Duke Energy Carolinas, LLC. Other states have also permitted a portion of costs related to incentive to be included in rates where the incentives are designed to achieve operational goals or achieve other benefits accruing to rate payers, which SCE&G's incentives do. The Commission believes that this approach is still just and reasonable from the evidence presented in the present proceeding.[31]

Based upon this reasoning, the Commission approved a stipulation which provided for a 50/50 sharing of the utility's incentive compensation costs in SCE&G's last rate case.

Q: IS YOUR RECOMMENDATION FOR THE TREATMENT OF ANNUAL INCENTIVE PLAN COSTS CONSISTENT WITH THIS APPROACH?

[31] *See* Application of South Carolina Electric & Gas Company ("SCE&G"), Docket No. 2012-218-E, Order Denying Petition for Rehearing, Order No. 2013-41, p.12. (Emphasis added).

A: Yes. I recommend, at a minimum, DESC's incentive compensation plan costs presented in this docket should be shared 50/50 between shareholders and ratepayers. Based on my review, there is evidence in this case to justify allocating ratepayers ***less than 50%*** of the AIP costs because (2) the plan is so heavily weighted in favor of financial performance metrics, and (2) the Company performs so poorly in customer satisfaction. Nevertheless, I recommend a 50/50 sharing of AIP costs.

Q: HOW DOES THE TREATMENT OF SHORT-TERM INCENTIVE COSTS IN THIS JURISDICTION COMPARE WITH OTHER JURISDICTIONS' TREATMENT OF INCENTIVE COMPENSATION?

A: The policy of excluding a portion of short-term compensation is consistent with the majority of jurisdictions. I have more than 25 years of experience in numerous jurisdictions testifying in regulatory proceedings involving annual incentive compensation plans. In conjunction with my work in this area, I have conducted an Incentive Compensation Survey of the 24 Western States, which has been taken by the Garrett Group in 2007, and updated in 2009, 2011, 2015 and 2018. The results show that a clear majority of the states surveyed follow the financial-performance rule, in which incentive payments associated with financial performance are excluded from rates. While some states disallow incentive pay using other criteria, and some states apply a sharing mechanism such as a 50%-50% allocation, none of the jurisdictions surveyed allow full recovery of incentive compensation through rates as a general rule. The results of the survey are set forth at Exhibit No. ___ (MG-3). The table below provides a summary of the survey results:

Garrett Group, LLC 24 Western State Incentive Survey Results			
No Incentive Costs Allowed in Rates	**Financial Performance Rule Followed**	**Other Sharing Approach**	**Incentives Not at Issue**
Hawaii			
	Arizona		
	Arkansas		
	California		
	Idaho		
	Kansas		
	Louisiana		
	Minnesota		
	Missouri		
	Nebraska		
	Nevada		
	New Mexico		
	North Dakota		
	Oklahoma		
	Oregon		
	South Dakota		
	Texas		
	Utah		
	Washington[32]		
	Wyoming		
		Alaska[33]	
		Colorado[34]	
			Iowa
			Montana

As shown in the table above, and presented in more detail in Exhibit No.___(MG-3), many of the western states disallow a portion of incentive compensation costs where the incentive plans contain both financial and operational measures. Of those jurisdictions, several use a sharing approach to allocate costs between shareholders and ratepayers.

[32] Washington has generally excluded a portion of financial-based incentives. See Exhibit No.___ (MG-3).

[33] Incentive compensation has not been an issue in the past, partly because most utilities in Alaska are municipalities and CO-OPs. In one recent case, however, the Commission approved incentives in rates, which may turn out to be an anomaly. See Exhibit No.___ (MG-3).

[34] Colorado followed the financial performance rule in the past. In one recent case, however, the Commission approved another approach, which may also be an anomaly. See Exhibit No.__(MG-3).

Q: WHAT ARE SOME EXAMPLES OF COMMISSIONS THAT USE A *SHARING* APPROACH?

A: In the survey of western states we identified several states that use a sharing approach, some of which include:

Arkansas: The Commission's policy is to disallow 50% of the short-term incentive plan costs in cases where the Company's incentive compensation plans has a financial performance funding mechanism.[35]

Arizona: The Arizona commission on numerous occasions has shared the cost of annual incentive plans on a 50% - 50% split between shareholders and ratepayers.[36]

Kansas: The Kansas commission disallows 100% of plans based on financial measures and 50% for plans using a balance of financial and operational measures.[37]

Oklahoma: The Commission excludes incentive payments tied to financial performance. The Commission does not determine the precise portion of the annual plans tied to financial measures but instead excludes 50% of the annual plans.[38]

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[35] See Arkansas Public Service Commission, Docket No. 13-028-U, Order No. 21, p.54; and Docket No. 15-011-U. Order No. 10, p. 22, (citing prior dockets: Docket No. 04-121-U (Order No. 16 at 23-25); Docket No. 04-176-U (Order No. 6 at 38-40); Docket No. 06-101-U (Order No. 10 at 62-69, which order as related to incentive compensation was upheld on appeal at 104 Ark. App. 147, 289 S.W.3d 513 (2008)).

[36] *See* for example, APS 2008 rate case, Decision 70360, Southwest Gas 2008 rate case, Decision 70665 and UNS Gas 2008 rate case, Decision 70011.

[37] *See* 2012 KCPL rate case, Cause No. 12-KCPE-764-RTS, in which short-term incentive costs were allocated 50%--50%.

[38] For electric utilities, the Public Utility Commission of Oklahoma has used a 50% sharing allocation for many years, in numerous cases. See e.g., OCC Final Order No. 672864, in PSO's last rate case, Cause No. PUD 201700151, p. 57. For gas utilities that use formula rates with an earnings-sharing mechanism, financial based incentives have been allowed because the increased earnings they generate are shared with customers.

Q: ARE THERE STATES WITH A MORE STRINGENT APPROACH?

A: Yes. The Texas commission's policy is more stringent. It has a longstanding policy of disallowing 100% of annual incentives that are directly tied to financial performance measures, and in addition, disallows 50% of the remaining incentives if they are ***indirectly*** tied to financial performance through an earnings-per-share funding mechanism.[39] In applying this approach in the Southwestern Electric Power Company (SWEPCO) case, in Docket No. 46449, the Public Utility Commission of Texas made the following finding:

> **194.** The Commission has repeatedly ruled that a utility cannot recover the cost of financially-based incentive compensation because *financial measures are of more immediate benefit to shareholders and financial measures are not necessary or reasonable to provide utility services*.[40]

In addition to Texas, Hawaii and Oregon also have more stringent policies, as set forth in Exhibit No. ___(MG-3).

Q: HAVE YOU REVIEWED THE TREATMENT OF INCENTIVE COMPENSATION IN JURISDICTIONS OTHER THAN THE 24 WESTERN STATES?

A: Yes. I recently surveyed the treatment in Illinois, Kentucky, Michigan and Wisconsin. Although regulatory commission's decisions typically are made on a case-by-case review of

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[39] *See* SPS Docket No. 43695, Order on Rehearing at 5-6. *Also see*, SWEPCO Docket No. 46495, and Docket No 46449.

[40] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 46449, Finding No. 194, Order on Rehearing at p. 34 (March 19, 2018). (Emphasis added).

the evidence presented, the general rule in these states is that financial-based incentives are not included in rates. The regulatory treatment in these states is set forth below:

Illinois: The general approach of the Illinois Commerce Commission has been that incentives based on financial goals are not allowed while those with operational goals are allowed in rates.[41] These criteria have been consistently applied by the Commission to short-term, long-term and executive incentive compensation. Long-term incentives are more often financially based and therefore more often disallowed. This treatment is the Commission's general practice, but it is also codified in the statute governing the formula rate plans for the state's two largest utilities (Ameren Illinois and Commonwealth Edison). Statute §220ILCS5/16-108.5c¶4(A) states:

> Recovery of incentive compensation expense that is based on the achievement of operational metrics, including metrics related to budget controls, outage duration and frequency, safety, customer service, efficiency and productivity, and environmental compliance. Incentive compensation expense that is based on net income or an affiliate's earnings per share shall not be recoverable under the performance-based formula rate.

Kentucky: Any incentive compensation related to financial metrics is disallowed 100%. This treatment is applied to short-term, long-term and executive incentives. This treatment is not proscribed by regulation or statue, but has been the longstanding practice of the Commission. This treatment is set forth in the recent Kentucky American rate case 18-00358 (20190627 PSC Order 01, pp 41-44)[42]. In this case, 100% of the long-term incentives were disallowed while 50% of the short-term incentives were allowed. Even though the short-term plan had a funding mechanism based on earnings per share, the plan's performance measures were 50% financial and 50% non-financial.

Michigan: Incentive compensation based on financial metrics are excluded from rates. Incentives with non-financial metrics which have a demonstrable benefit to ratepayers are allowed in rates. This treatment is used for all incentive compensation and can produce a different result for short-term verses long-term and executive plans which are often stock-based plans which are not included in rates. There are no statues requiring this treatment, but it is the Commission's well-established policy based on consistent

[41] See Commonwealth Edison, Docket No. 05-0597, pp. 95-97 (affirmed on appeal); North Shore Gas/Peoples Gas, Docket Nos. 09-0166 and 09-0167, (affirmed on appeal); and Illinois-American Water Co., Order No. 16-0093, p. 37.

[42] See also KPC 14-00396 20150622_PSC_ORDER (pp. 24-26)

precedent. This treatment is set forth in Consumers Energy Company Electric Rate Case U-18322 and DTE Electric Rate Case U-20162.[43]

Wisconsin: Incentive compensation based on financial metrics are excluded from rates, as the commission has found that such plans do not reasonably provide benefits to ratepayers when tied to financial metrics.[44] In the Wisconsin Public Service 2013 rate case, the commission stated:

> The Commission is not persuaded it should change its practice of excluding incentive compensation from revenue requirements of the major investor-owned utilities in Wisconsin. WPSC has not demonstrated that the plans provide substantial ratepayer benefit with enough quantified permanent savings to ratepayers to warrant inclusion of the costs in revenue requirement. With the majority of executive incentive performance measures still tied to meeting earnings per share criteria, and the non-executive incentive performance measures that weigh heavily on measures tied to the shareholders benefit, <u>the Commission finds it is reasonable to exclude all incentive compensation costs from the revenue requirement</u>.[45]

Q: IN YOUR EXPERIENCE, WHEN REGULATORS EXCLUDE THE PORTION OF A UTILITY'S INCENTIVE PLAN TIED TO FINANCIAL PERFORMANCE MEASURES, DOES THE UTILITY STOP OFFERING INCENTIVE COMPENSATION TO HELP ACHIEVE ITS FINANCIAL GOALS?

No. Even though regulators generally disallow incentive compensation tied to financial performance for ratemaking purposes, utilities continue to include financial performance as a key component of their plans. In my opinion, utilities continue to tie incentive payments to financial performance because by doing so they achieve the primary objective of the incentive plans: to increase corporate earnings and, thereby, earnings per share

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[43] In the U-20162 Order, the Michigan commission cites Staff's Initial Brief (pp. 67-68) in which Staff lists 11 prior cases in which the commission disallowed financially-based incentive compensation which does not benefit ratepayers.

[44]See Northern States Power Co., Docket 4220-UR-123, issued December 21, 2017, p. 16.

[45]Wisconsin Public Service, Docket 6690-UR-122, issued December 18, 2013, p. 24. (Emphasis added).

(EPS). However, since the utility retains the increased earnings these plans help achieve, payments for these plans should be made from a portion of the increased earnings. These plans need not be subsidized by ratepayers. Recovery of plan costs through rates ***is not necessary to attract a talented workforce*** because the utility has other means of cost recovery—through the increased earnings generated by the plan.

Q: WHAT IS THE GENERAL RATIONALE FOR EXCLUDING INCENTIVE COMPENSATION TIED TO FINANCIAL PERFORMANCE?

A: In most jurisdictions, the cost of incentive plans which are tied to financial performance measures are excluded for ratemaking purposes. When the costs associated with these plans are excluded, the ***primary*** rationale is that financially-based incentives benefit shareholders more than they do ratepayers. Other rationale used by the regulators is generally based on one or more of the following reasons:

(1) **Payment is uncertain.** Often, payment of incentive compensation is conditioned upon meeting some predetermined financial goal such as achieving a certain increase in earnings, reaching a targeted stock price or meeting budget objectives. If the predetermined goals are not met, the incentive payment is not made, or payment is made at some lesser amount. Therefore, one cannot know from year to year what the level of the payment may be or whether the payment will be made at all. It is generally considered inappropriate to set rates to recover a tentative level of expense.[46]

(2) **Many of the factors that significantly impact earnings are outside the control of most company employees and have limited value to customers.** For example, an unusually hot summer can easily trigger an incentive payment based on

[46] PSO's experience with its 2008 rate case proceeding, in Oklahoma PUD 2008-00144, is a good example of this problem. In 2009, PSO's below target EPS reduced the funding available for incentive compensation payments by 76.9%. Although in the PSO's 2008 rate case, the Oklahoma commission had included more than $4 million in rates for incentives, PSO chose not to use all of that money to pay incentives but instead retained some of those funds for its shareholders to help bolster the Company's lower earnings that year.

company earnings for an electric utility, as a cold winter can for a gas utility. Obviously, weather conditions are outside the control of utility employees and customers receive no benefit from the higher utility bills that result from an unusually hot or cold weather. Similarly, company earnings may increase, thus triggering incentive payments, as a result of customer growth, which commonly occurs without significant influence from company personnel. In fairness, since shareholders enjoy the benefits of customer growth between rate cases, shareholders should also bear the cost of any incentive payments such growth may trigger. Finally, utility earnings may increase substantially if the utility is able to successfully argue for a higher ROE in a rate case proceeding. Utility efforts to maximize ROE in a rate proceeding, however, have little to do with improving overall employee performance across the company. If utility employees gear their efforts toward securing an *unreasonably* high ROE in a rate proceeding, the incentive mechanism actually would work to the detriment of the utility customers.

(3) **Earnings-based incentive plans can discourage conservation.** When incentive payments are based on earnings, employees may not support conservation programs designed to reduce usage if they perceive these programs could adversely impact incentive payment levels. To the extent that earnings-based incentive plans discourage conservation and demand-side management programs, these plans do not serve the public interest. The growing focus on energy efficiency at both the national and state level renders this point especially important.

(4) **The utility and its stockholders assume none of the financial risks associated with incentive payments.** Ratepayers assume the risk that the utility will instead retain the amounts collected through rates for incentive payments whenever targeted increases are not reached. Employees assume the risk that the incentive payments will not be made in a given year. The utility and its stockholders, however, assume no risk associated with these payments. Instead, the company's only responsibility is to decide who gets the money, the stockholders or the employees.[47]

(5) **Incentive payments based on financial performance measures should be made out of increased earnings.** Whatever the targets or goals may be that trigger an incentive payment, when the plan is based in whole or in part on financial performance measures the company always obtains a financial benefit from achieving these objectives. This financial benefit should provide ample funds from which to make the payment. If not, the incentive plan was poorly conceived in the first place. As such, employees should be compensated out of the increased earnings, and not through rates.

[47] *Id.*

(6) **Incentive payments embedded in rates shelter the utility against the risk of earnings erosion through attrition.** When utilities are allowed to embed amounts for incentive payments in rates, that money is available to the utility not only to pay the incentive payment when financial performance goals are met but also to supplement earnings in those years when the company does not perform well. In those years when financial performance measures are met, the increased earnings of the company provide ample additional funds from which to make the incentive payments to employees, and the incentive payment amount embedded in rates is not needed. In those years when financial performance measures are not met and the incentive payments are not made, the amount embedded in rates for incentive payments acts as a financial hedge to shelter the poor financial performance of the company.

Q: UTILITIES OFTEN ASSERT THAT INCENTIVE PLANS SHOULD BE INCLUDED IN RATES BECAUSE THEY ARE PART OF A TOTAL COMPENSATION PACKAGE AND ARE COMPARABLE WITH THE COMPENSATION PAID BY OTHER UTILITIES. DO YOU AGREE?

A: No. The rationale typically given for including incentive pay in rates is that incentive pay should be included in rates because it is needed to attract and retain qualified personnel. However, the argument is problematic. First, it misses the point. The question for regulators is not about what compensation the ***company*** should pay; the question for regulators is what amount of that compensation ***ratepayers*** should pay. The utility is free to offer whatever compensation package it deems appropriate, but most regulatory commissions agree that ratepayers should not pay the costs of plans designed to increase corporate earnings. Also, because incentive pay related to financial performance is generally disallowed, most of the utilities that compete with for talent generally do not recover all of their incentive compensation in rates. Therefore, a utility ***is not put at a competitive disadvantage*** when its incentive pay is similarly adjusted.

The other common problem with the "total compensation package" argument is that when an incentive payment is based on achieving financial performance goals there should be a financial benefit to the company that comes from achieving these goals. This financial benefit should provide ample ***additional*** funds from which to make the incentive payments. If not, the plan was poorly conceived. Thus, a utility is not placed at a competitive disadvantage when incentive payments tied to financial performance are not collected through rates, because the funding for these payments should come out of the additional earnings the incentive plans help achieve.

Q: UTILITIES ALSO CLAIM INCENTIVE COMPENSATION COSTS ARE NECESSARY TO ATTRACT AND RETAIN QUALIFIED PERSONNEL TO PROVIDE SAFE AND RELIABLE SERVICE. DO YOU AGREE?

A: No. Utilities often claim their incentive compensation plans are necessary for attracting talent to provide safe and reliable service. The problem with this assertion is that it is not actually true. Much of the electricity in this country is provided by municipal electric providers that do not pay short-term incentives, yet they are able to attract talent sufficient to deliver safe and reliable service. Electric cooperatives also provide a substantial amount of the electricity used in this country but many do so without the use of short-term incentives.[48] Likewise, many state-run electric systems also provide electric service without the use of short-term incentives, as do some federally-owned utilities. So, it is inaccurate to say that incentives are ***necessary*** for the provision of electric service.

[48] *Id.*

The other problem with this argument is that it does not explain why incentive pay should be included in rates. Virtually all utilities have the same need to attract qualified employees, but many of these other utilities are ***not recovering*** the full amount of their incentive pay in rates, particularly when incentive pay is tied to the financial performance.

Q: ARE YOU RECOMMENDING THAT THE COMPANY ELIMINATE ITS SHORT-TERM INCENTIVES?

A: No. The question for ratemaking purposes is not whether the utility should offer short-term incentives to its employees; the question is, who should pay for them. The consensus view is that financial-based incentives benefit the shareholders more than they do the ratepayers, and, as a result, should be paid for by the shareholders. This point was addressed by the Public Service Commission of Wisconsin:

> In this case, the Commission finds that it is not reasonable to include the cost of NSPW's AIP in the revenue requirement. First, no AIP payments are made unless a financial metric, that benefits shareholders, is met. While NSPW may consider financial performance triggers irrelevant, the Commission finds that NSPW's current AIP program does not reasonably provide benefits to NSPW's ratepayers when it continues to be tied to a financial metric. Second, the Commission is not persuaded by NSPW's arguments that its overall compensation without the AIP would fall below market rates. The Commission is also not persuaded by NSPW's argument that recovery of the AIP expense from ratepayers is required in order for NSPW to attract and compete for employees. NSPW provided no evidence of any unsuccessful recruitments or other examples of any difficulty in hiring talented employees because NSPW is not recovering its AIP payments in rates. ***NSPW's management is not prohibited from paying a portion of its overall 2018 employee compensation in the form of incentives***. However, the amount of payroll expense authorized for recovery is limited to what the Commission has determined to be reasonable in this case.[49]

[49] Northern States Power Company, 2018 Rate Case, Docket No. 4220-UR-123, at p. 16.

Q: WHAT ARE YOU RECOMMENDING WITH RESPECT TO THE COMPANY'S INCENTIVE EXPENSE?

A: The AIP is ***strongly tied*** to financial performance measures. As discussed in the section above, several factors indicate that Dominion Energy's composite AIP is more strongly tied to financial goals than operational goals, and therefore on balance, is likely to benefit Dominion Energy shareholders more than DESC customers. Moreover, although the Company claims it has achieved satisfactory performance in operational categories, there is objective evidence that the Company has performed well ***below average*** in customer satisfaction.[50] Based on these factors, ***it would be reasonable to disallow more than 50%*** of the annual incentive plan costs. Nevertheless, I am recommending that the Commission adopt a ***50% - 50% sharing approach.*** This is consistent with the Commission's prior treatment of the Company's incentive compensation, and is a reasonable approach that recognizes the Company's plan is based on financial and operational performance measures which benefit shareholders and ratepayers. I propose an adjustment to remove 50% of the annual incentive plan costs included in pro forma operating expense in the amount of $5,651,215, and attendant payroll taxes in the amount of $489,982. The calculations supporting this adjustment are set forth at Exhibit No.___(MG-2).

[50] See *e.g.*, J.D. Power 2019 Customer Satisfaction survey.

II. E. LONG-TERM EXECUTIVE STOCK INCENTIVE PLAN

Q: WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO THE RECOVERY OF LONG-TERM STOCK INCENTIVE PLAN FOR EXECUTIVES?

A: The Company seeks to recover long-term incentive plan expense of $915,832.[51]

Q: PLEASE DESCRIBE THE COMPANY'S LONG-TERM COMPENSATION PLANS.

A: In addition to the company-wide short-term incentive plans discussed above, executives and managers of the Company are provided Long-Term Incentive Plan ("LTIP") compensation.[52] Dominion Energy's 2019 long-term incentive consisted of restricted stock grants, which were awarded in 2019 and will vest after three years. For executives, half of the 2019 long-term incentive target amount was provided in the form of restricted stock grants, which vest after three years. The other half was provided in the form of performance awards. The 2019 performance awards have a three-year performance period ending December 31, 2021. The value of these performance awards will be calculated in early 2022, at between 0% and 200% of their awarded amount.[53] Ms. Elbert states:

> Their value will depend on two equally-weighted metrics: relative total shareholder return ("TSR") and return on invested capital ("ROIC"). There are additional opportunities to earn a portion of the performance award based on absolute TSR or relative price earnings (P/E) ratio performance as measured against peer companies. The performance grants are issued either in the form of cash or Dominion Energy stock. [54]

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[51] See Response to ORS-1-5, Attachment 1-5, PF Adj #2 Incentive Pay Adjustment.xlsx.
[52] Direct Testimony of Regina J. Elbert, p.20, line 15—p.21, line 10.
[53] *Id.*, p. 20, lines 19-21.
[54] *Id.*, p.21, line 21—p.22, line 4.

The plan is designed to ensure that the recipients of LTIP are "invested in the long-term performance of the company."[55] Ms. Elbert explained in her testimony, "Performance grants are issued in stock until the executive has achieved at least 50% of his or her stock ownership target as of the date of grant. Thereafter, it can be issued in cash."[56]

Q: WHAT IS THE RATIONALE FOR EXCLUDING LONG-TERM INCENTIVE COMPENSATION EXPENSE?

A: Long term incentives, especially stock-based incentives, are financial-based incentives and should be disallowed for all of the reasons set forth in the previous section. Incentive compensation payments to officers, executives, and key employees of a utility, such as the long-term incentive payments, are generally excluded for ratemaking purposes. Officers of any corporation have a fiduciary duty to the corporation to put the interests of the company first. Undoubtedly, the interests of the Company and the interests of the customer are not always the same, and at times, can be quite divergent. This natural divergence of interests creates a situation where not every cost associated with executive compensation is presumed to be a necessary cost of providing utility service. Many regulators are inclined to exclude executive bonuses, incentive compensation and supplemental benefits from utility rates, understanding that these costs would be better borne by the utility shareholders.

It has been my experience that many utilities treat long-term executive incentive compensation costs as a below-the-line item in their rate case application.

[55] *Id.*, p.21, lines 7-8.
[56] *Id.,* p. 21, lines 9-10.

Further, long-term incentive plans are specifically designed to tie compensation to the financial performance of the company. This is done to further align the interest of the employee with those of the shareholder. Because the compensation of the employee is tied over a long period of time to the company's stock price, it motivates employees to make business decisions from the perspective of long-term shareholders. This intentional alignment of employee and shareholder interests means the costs of these plans should be borne solely by the shareholders. It would be inappropriate to require ratepayers to bear the costs of incentive plans designed to encourage employees to put the interests of the shareholders first.

Q: HOW IS LONG-TERM INCENTIVE COMPENSATION TREATED IN OTHER JURISDICTIONS?

A: The results of the Garrett Group Incentive Compensation Survey, discussed in the previous section of this testimony, show that most states follow the general rule that incentive pay associated with financial performance is not allowed in rates. This means that recovery of long-term, stock-based incentives are ***not allowed*** in most states.

According to the survey, 20 of the 24 western states tend to ***exclude*** all or virtually all long-term stock-based incentive pay, either through an outright ban on stock-based incentives or through applying the *financial performance* rule, which has the effect of excluding long-term earnings-based and stock-based awards. These states include Arizona, Arkansas, California, Colorado, Hawaii, Idaho, Kansas, Louisiana, Minnesota, Missouri, Nevada, New Mexico, North Dakota, Oklahoma, Oregon, South Dakota, Texas, Utah, Washington and Wyoming. In the other four states surveyed, Alaska, Iowa, Montana and Nebraska, the issue just has not been addressed.

Q: WHEN UTILITIES SEEK TO RECOVER LONG-TERM INCENTIVE COMPENSATION IN RATES, WHAT RATIONALE IS GENERALLY PROVIDED?

A: Generally, utilities argue that long-term incentives are part of an overall compensation package that is designed to attract and retain qualified personnel. Because other utilities offer incentive plans to their executives, a company would run the risk of not being able to compete for key personnel if it did not offer a comparable plan.

Q: IS THIS ARGUMENT PLAUSIBLE?

A: No. The problem with this argument is that when utilities compete with other utilities for qualified executives, and the long-term incentive compensation plans of those other utilities are <u>not</u> being recovered through rates, the utility is not placed at a competitive disadvantage when its long-term incentive compensation is excluded as well. The fact that other utilities offer long-term incentive plans is not relevant; what is relevant is the fact that other utilities are not recovering the costs of those plans in rates. In an order disallowing Nevada Power's long-term incentive plan, the Public Utility Commission of Nevada articulated this important ratemaking concept:

> Therefore, the Commission accepts BCP's and SNHG's recommendations to disallow recovery of expenses associated with LTIP. Both parties provide a valid argument that this type of incentive plan is mainly for the benefit of shareholders. Further, both

> BCP and SNHG provide examples of numerous other jurisdictions that do not allow the recovery of these costs and, *therefore, disallowance in this instance would not place NPC in a competitive disadvantage*.[57] (Emphasis added).

Further, the problem with the "total compensation package" argument is that when an incentive payment is paid based on the achievement of financial performance goals there should be sufficient financial benefit to the company as the result of achieving these goals. This financial benefit should provide ample additional funds from which to make the incentive payments. If not, the plan was poorly conceived. Thus, a utility is not placed at a competitive disadvantage when incentive payments tied to financial performance are not collected through rates, because the funding for these payments should come out of the additional earnings the incentive plans help achieve.

Q: WHAT OTHER RATIONALE DO UTILITIES TYPICALLY PROVIDE FOR INCLUDING LONG-TERM STOCK-BASED INCENTIVES IN RATES?

A: Companies claim that long-term incentives are *necessary* costs, and, as such, they should be included in rates. As discussed previously in my testimony, when tested, this assertion does not prove to be true. As discussed earlier in this testimony, much of the electricity in this country is provided by *municipal electric providers* virtually none of which pay long-term stock-based incentives, yet they are able to attract talent sufficient to deliver safe and reliable electric service. *Electric cooperatives* also provide a substantial amount of the electricity used in this country, but do so without the use of long-term stock-based

[57] See Final Order in Docket 08-12002 at paragraph 549.

incentives. Likewise, *state-run electric systems* provide electric service without the use of long-term stock-based incentives, as do *federally-owned utilities*. So, if municipalities, cooperatives, state and federally-run electric systems can provide electric service without the use of long-term stock-based incentive compensation, I believe it is inaccurate to say that long-term stock-based incentives are *necessary* for the provision of electric service.

Q: WHAT IS THE IMPACT OF YOUR ADJUSTMENT TO EXCLUDE THE COMPANY'S LONG-TERM STOCK INCENTIVE PLAN COSTS?

A: My adjustment removes 100% of the long-term incentive plan costs included in pro forma operating expense in the amount of $915,832. The calculations supporting this adjustment are set forth at Exhibit No. ___(MG-2).

II. F. <u>VEGETATION MANAGEMENT ADJUSTMENT</u>

Q. PLEASE DISCUSS THE COMPANY'S REQUEST FOR A VEGETATION MANAGEMENT ACCRUAL AND RESERVE ACCOUNT.

A. DESC is requesting an accrual for its proposed vegetation management expense based on a five year operating cycle with the costs to be tracked and any over or under recovery of those costs to be included in rate base in a future rate case.[58] The adjustment is based on proxy costs and miles of lines trimming over the five year period 2015 through 2019.[59] According to Mr. Coffer, this adjustment increased the test year vegetation management

[58] See Direct Testimony of Keith C. Coffer, p. 19, lines 4-16.
[59] See Response to ORS-1-5, Attachment 1-5 PF Adj #21 Veg Mang.xlsx, (tab Projected Costs).

expenses by $3,519,375.[60]

Q. HOW MUCH HAS DESC SPENT ON VEGETATION MANAGEMENT IN RECENT YEARS?

A. DESC reports the following operating and maintenance ("O&M") costs for vegetation management:[61]

Year	O&M – Tree Trimming	O&M – Herbicide	Total O&M Expense	Incr(Decr) From PY/Avg
2015	$23,449,255	$100,198	$23,549,453	-
2016	$19,242,386	$103,670	$19,346,056	$(4,203,397)
2017	$19,091,017	$99,500	$19,190,517	$(155,539)
2018	$18,894,081	$96,607	$18,990,688	$(199,829)
2019(TY)	$24,824,575	$106,612	$24,931,187	$5,940,499
Totals	$105,501,313	$106,612	$24,931,187	-
5-YR Average	$21,100,263	$101,317	$21,240,316	$3,729,607

DESC's vegetation management costs show a similar trend, with the test year costs being $5,940,499 higher than the 2018 costs, and $3,729,607 higher than the five-year average expense level.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSALS TO ESTABLISH A VEGETATION MANAGEMENT ACCRUAL AND TO INCREASE VEGETATION MANAGEMENT EXPENSES?

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60 See Direct Testimony of Keith C. Coffer, p. 19, lines 20-21. During the discovery phase of the case, the Company provided a correction to vegetation management costs in ORS-DESC 8-6 Supplemental. The Company's supplemental proposed adjustment is $3,786,426.
61 See the response to DOD-FEA 3-51.

A. No. The use of a tracking mechanism shifts the risks of operating the utility from the Company to the customers. Moreover, tracking mechanisms tend to weaken managements' incentive to control costs.

Q. WHAT IS YOUR RECOMMENDATION FOR THE RECOVERY OF VEGETATION MANAGEMENT EXPENSES?

A. I recommend that the Company recover the test year level of vegetation management expenses. The test year vegetation management expenses of $24.9 million represents a $5.9 million increase over the prior year actual cost, and $3.7 million over the 5-year average. The Company's adjustment to increase the expense above the test year cost level is unnecessary. I recommend that the Company's adjustment be reversed.

Q. WHAT IS YOUR RECOMMENDATION ON DESC'S REQUEST TO TRACK THE VEGETATION MANAGEMENT COSTS?

A. I recommend that the request to establish an accrual and track the costs be denied because the proposal shifts risk from shareholders to ratepayers.

Q. WHAT ADJUSTMENT DO YOU RECOMMEND TO THE REQUESTED VEGETATION MANAGEMENT EXPSENSE?

A. I recommend that the requested vegetation management expenses be reduced by $3,519,375 to reverse the proposed increase by DESC. This adjustment can be found on Exhibit No.___(MG-2).

II. G. STORM DAMAGE RESERVE

Q. PLEASE DISCUSS THE COMPANY'S REQUEST TO REINSTATE THE STORM DAMAGE REMEDIATION RIDER AND THE STORM DAMAGE RESERVE.

A. DESC requested the reinstatement of a rider to fund a storm damage remediation asset to cover the cost of storm damages that exceed the embedded expense level of $2.5 million. The rider was first authorized with Order No. 1996-15 but was suspended with Order No. 2010-471. The suspension was continued in Order No. 2012-951, and the reserve had a balance of $30 million at that time. The Company is proposing to collect $9,839,863 from retail ratepayers annually to fund the reserve. This amount is in addition to a requested annual amortization of past storm costs of $8.8 million. The Company is requesting a total of $18.6 million annually in retail rates for storm damages over the test year expense level, consisting of $8.8 million of past storm costs and $9.8 million of future costs.

Q. DO YOU AGREE WITH THE COMPANY'S REQUEST THAT RATEPAYERS PAY A COMBINED $18.6 MILLION IN STORM DAMAGE EXPENSES?

A. No. In Docket 2012-218-E, it was agreed that the availability of an after-the-fact recovery of losses from major storms was a reasonable alternative to a pre-funded storm reserve. The Commission stated:

> All parties to this proceeding, including the ORS, are in agreement that collection of the storm damage reserve rider should not be reinstated at this time, and the storm damage insurance policy that is linked to the reserve should be allowed to lapse. Company witness Kissam has testified that the availability of an after-the-fact rate rider to recover storm damage response and restoration costs is an acceptable alternative to the continued collection

> of the storm damage rider and storm damage insurance. Tr. at 419-420. For that reason, and considering the agreement of all parties to the recommendations contained in the MOU, the Commission accepts the recommendation of the parties and finds it to be just and reasonable to rule that the storm damage reserve rider not be collected and the storm damage insurance policy be allowed to lapse.[62]

In its order in Docket 2012-218-E, the Commission found it was appropriate to continue the suspension of the storm damage reserve indefinitely, subject to future reinstatement by the Commission.

Q: SHOULD THE COMMISSION REINSTATE THE STORM DAMAGE RESERVE AT THIS TIME?

A: No. Under the current economic conditions, it would <u>not</u> be appropriate to reinstate the costly storm damage reserve as the Company requests, which would require ratepayers to pay for both past costs and future costs at the same time. The pre-funding of future costs also unfairly shifts the responsibility for funding utility investment from shareholders to ratepayers. The availability of an after the fact recovery of losses from major storms should be sufficient assurance for shareholders to continue covering storm losses until a proceeding can be held to provide for the recovery of those losses.

Q. WHAT IS THE AMOUNT OF THE ADJUSTMENT TO REMOVE THE COSTS RELATED TO THE STORM DAMAGE REMEDIATION RIDER?

[62] See SCE&G Application for Increases an Adjustments in Electric Rates, Docket No. 2012-218-E, Order No. 2012-951, pp. 40-41.

A. The adjustment to remove the costs of the storm damage remediation rider reduce O&M expenses by $9.840 million the storm reserve liability by $7.385 million and working capital by $1.230 million. This adjustment can be found on Exhibit No. ___ (MG-2).

II. H. CANADYS UNITS 2 AND 3 AMORTIZATION (UNRECOVERED PLANT)

Q: WHAT IS THE COMPANY RECOMMENDING WITH RESPECT TO THE RETIRED CANADYS PLANT AMORTIZATION?

A: Mr. Coffer testifies that the Company completed its retirement of the Canadys coal-fired generating station with the removal of Units 2 and 3.[63] He further testifies that, pursuant to Commission Order No. 2013-649, the retired Canadys Units 2 and 3 are being amortized at the level of depreciation expense ($12.3 million per year) that was being recorded for the Canadys Units before their retirement.[64] The Company is asking that the Commission affirm this amortization schedule and include the unrecovered balance in rate base.[65]

Q: WHAT IS THE IMPACT ON RATES OF THE COMPANY'S REQUESTED TREATMENT?

A: The unrecovered balance of Canadys Units 2 and 3 is $72,551,742.[66] A full rate base return on this amount costs ratepayers approximately $7.5 million per year.[67] Along with the $12.3 million amortization, the full annual burden on ratepayers is about $19.8 million

[63] See Direct Testimony of Keith C. Coffer, at page 28.
[64] *Id.*
[65] *Id.*
[66] See Response to ORS 7-07, Attach. 1822108-12-31-2019response.xlxs, Tab FH 182.2108 Summary.
[67] $72,551,742 x 10.33619 (Co. WACC) = $7.5 million.

per year. In other words, ratepayers are being asked to pay about $20 million per year for a plant that no longer operates.

Q: DO YOU AGREE WITH THIS TREATMENT?

A: No, not necessarily. I agree with what the Commission has done with this issue up to this point in time. Because the plant was retired between rate cases, the appropriate treatment was to leave the plant in rate base and continue with the scheduled depreciation recoveries, because to do anything else would be single-issue ratemaking. Moreover, this is exactly the result that would have occurred naturally if an accounting order had not been issued by the Commission when the plant retired – the plant would have remained in rate base and the depreciation recoveries would have continued to be collected in rates.

However, now that there is a rate case, the Commission has the opportunity to evaluate the current situation and to decide (1) whether to include a plant that is no longer used and useful in rate base, (2) whether to allow the remaining balance to be collected in rates and (3) if recovery is allowed, over what period of time should the recovery occur. In other words, once a plant is no longer used and useful, the Commission must decide whether to allow a return on and return of the remaining balance.

Q: ARE THERE EXAMPLES FROM OTHER STATES WHERE UTILITIES WERE ALLOWED LESS THAN A FULL RECOVERY OF STRANDED COAL PLANT BALANCES?

A: Yes. There are many such examples. In New Mexico, Public Service Company of New Mexico ("PNM") agreed to write-off 50% of the stranded costs associated with two coal units retired as part of its environmental compliance plan for Regional Haze.[68] One of PNM's coal facilities, the San Juan Generating Station ("SJGS"), consists of four coal-fired units with 1,683 net megawatts ("MW") of electric generation capacity. PNM's State Implementation Plant ("SIP") sought approval to (a) abandon two coal plants at San Juan Units 2 and 3 and (b) issue Certificates of Public Convenience and Necessity ("CCN") for replacement power resources. As part of the settlement in that case, PNM agreed to write-off 50% of the stranded book value of the plant assets at retirement and place the remaining balance in a regulatory asset account when the plant is retired and recover that balance over a 20-year amortization period. The stipulation language is set forth below:

Undepreciated Investment in Retired Plant

> 18. PNM shall be allowed to recover 50% of its undepreciated investment in SJGS Units 2 and 3 as shown on its books as of December 3~1, 2017, after reducing the net book value of SJGS Unit 3 by $26 million to reflect the value placed on the additional SJGS Unit 4 capacity. Until that time, PNM shall continue to depreciate SJGS Units 2 and 3 according to its approved depreciation schedules. Based on current projections, PNM estimates its undepreciated investment in SJGS Units 2 and 3 will be approximately $257.0 million at December 31, 2017. Based on this estimate, PNM will be allowed to recover 50% of the undepreciated investment estimated at $115.5 million, which is $257.0 million less $26.0 million transferred to Unit 4, i.e., $231.0 million, multiplied by 50% as the percentage of recovery agreed to in this Stipulation. PNM shall place the amount of undepreciated investment allowed to be recovered in a regulatory asset which shall be amortized over a twenty year period with a carrying charge equal to PNM's pretax weighted average cost of capital

[68] The federal Regional Haze Rule was issued by the U. S. Environmental Protection Agency ("EPA") under the Clean Air Act ("CAA").

("WACC") (as it may be modified from time to time by Commission orders in rate cases) on the unamortized amount.[69]

Q: ARE THERE OTHER EXAMPLES?

Yes. Southwestern Electric Power Company ("SWEPCO") retired the Welsh 2 plant in April 2016 after only 38 years of commercial service. In its 2016 rate case, SWEPCO sought to include the remaining $75.4 million balance for the Welsh plant in rate base. The Texas Public Utility Commission, however, denied the utility's request and ordered the following treatment for the Welsh 2 plant retirement, as shown below in the excerpts from the order:[70]

> 63. The decision to retire Welsh unit 2 was part of a reasonable and balanced resource portfolio management strategy, which by retrofitting some units and retiring others, allowed SWEPCO to manage the overall concentration of solid fuels in the portfolio as a hedge against future, more-stringent environmental-compliance requirements.
>
> 64. SWEPCO management prudently determined to retire Welsh unit 2.
>
> 65. SWEPCO retired Welsh unit 2 in April of 2016.
>
> 66. Welsh unit 2 no longer generates electricity and is not used by and useful to SWEPCO in providing electric service to the public.
>
> . . .
>
> 68. Because Welsh unit 2 is no longer used and useful, SWEPCO may not include its investment associated with the plant in its rate base, and may not earn a return on that remaining investment.
>
> 69. Allowing SWEPCO a return of, but not on, its remaining investment in Welsh unit 2 balances the interests of ratepayers and shareholders with respect to a plant that no longer provides service.

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[69] See Stipulation filed October 1, 2014 in NMPRC Case No. 13-00390-UT, p. 6.
[70] *See* Texas PUC order in Docket No. 46449 at paragraphs 63 through 71.

> 70. It is reasonable for SWEPCO to recover the remaining undepreciated balance of Welsh unit 2 over the 24-year remaining lives of Welsh units 1 and 3.
>
> 71. The appropriate accounting treatment that results in the appropriate ratemaking treatment is to record the undepreciated balance of Welsh unit 2 in a regulatory-asset account.[71]

This order follows the treatment recommended in my testimony above: (1) the retired plant balance was transferred to a regulatory asset account, (2) the regulatory asset account was amortized over the remaining useful lives of the remaining Welsh assets, and (3) the regulatory asset balance was ***excluded from rate base*** because the plant was no longer used and useful. This was the treatment prescribed in Texas because the Texas PUC found the that the retirement of the Welsh plant was a prudent decision. If the commission had found that the retirement was not prudent, it could have excluded the asset from rate base *and* not allowed any amortization of the remaining balance.

Q: ARE YOU AWARE OF ANOTHER EXAMPLE?

Yes. Another example occurred when American Electric Power's ("AEP") subsidiary, Public Service Company of Oklahoma ("PSO"), retired its Northeastern 4 Plant. In that case, the Oklahoma Corporation Commission allowed PSO to recover only a cost of debt return on the stranded cost balance because the plant was no longer used and useful.[72]

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[71] *See* Texas PUC order in Docket No. 46449 at paragraphs 63 through 71.
[72] See Cause No. PUD 201700151, Order No. 672954, p. 3.

Q: IF THIS COMMISSION FOLLOWED THE APPROACH OF EXCLUDING THE PLANT FROM RATE BASE ON THE GROUNDS THAT THE PLANT IS NO LONGER USED AND USEFUL, WHAT WOULD BE THE IMPACT ON RATES?

A: As discussed earlier, the unrecovered balance of Canadys Units 2 and 3 is $72,551,742.[73] A full rate base return on this amount costs ratepayers approximately $7.5million per year.[74]

Q: IF THE COMMISSION DECIDES TO INCLUDE THE UNRECOVERED CANADYS PLANT BALANCE IN RATE BASE, ARE THERE OTHER THINGS THE COMMISSION COULD DO TO MITIGATE THE RATE IMPACT FOR CURRENT RATEPAYERS?

A: Yes. The current amortization of the remaining balance is about $12.3 million per year. At this pace, the remaining balance on the plant of $72.5 million will be recovered in about 6 years. The Commission could extend the recovery period to help reduce the current burden on ratepayers. With the remaining balance being included in rate base, the Company is financially indifferent to the period of time over which it recovers the balance. In other words, the net present value of $72.5 million recovered over 6 years or 40 years is still $72.5 million so long as the unrecovered balance is earning a full rate base return during the recovery period.

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[73] See FH 182.2108 Summary.
[74] $72,551,742 x 10.33619 (Co. WACC) = $7.5 million.

Q: WHAT WOULD A REASONABLE RECOVERY PERIOD BE FOR THE UNRECOVERED CANADYS PLANT?

A: The unrecovered balance could be amortized over the useful life of a proxy-plant replacement for the Canadys capacity, in other words, over the useful life of combined-cycle gas plant, about 40 years. This would save ratepayers about $10.5 million per year.

Q: COULD THE COMMISSION EXCLUDE THE UNRECOVERED BALANCE FROM RATE BASE AND EXTEND THE AMORTIZATION PERIOD?

A: It could. However, I believe the better balance between shareholders and ratepayers for an early-retired plant that is excluded from rate base is to allow the utility to recover the balance over the same recovery period that existed when the plant was retired, which is the 6-year recovery period here. However, if the Commission were to allow the unrecovered balance in rate base, it should extend the recovery period to help alleviate the burden on current ratepayers.

Q: WHAT DO YOU RECOMMEND?

A: I recommend that the Commission include the unrecovered Canadys plant in rate base and extend the recovery period to 40 years. The Commission could, in a subsequent rate case proceeding, re-visit the issue and shorten the amortization period if appropriate once rates have stabilized for DESC. My adjustment in the amount of $10.512 million can be seen at Exhibit No.___(MG-2).

II. I. CRITICAL INFRASTRUCTURE COST DEFERALS

Q: WHAT IS THE COMPANY RECOMMENDING WITH RESPECT TO THE CRITICAL INFRASTRUCTURE PROTECTION COST DEFERRALS?

A: Mr. Coffer explains in his direct testimony that in Order No. 2014-946, the Commission authorized the deferral of up to $20,000,000 of incremental costs incurred by the Company from January 1, 2015, through December 31, 2019, to comply with critical infrastructure protection reliability standards promulgated by the Federal Energy Regulatory Commission ("FERC").[75] The Commission also authorized the Company to accrue carrying costs on the deferred balance.[76] In this case, the Company is proposing to amortize the deferred balance, including carry, totaling $24,579,421 over a five-year period.[77] The effect of this adjustment is an increase to Test Year O&M of $4,372,953, an increase to Test Year amortization expense of $ 542,932 and an increase to rate base of $14,757,486.[78]

Q: DO YOU AGREE WITH THE COMPANY'S PROPOSED AMORTIZATION PERIOD?

A: No. The Company's proposed 5-year amortization period is unduly accelerated under the circumstances and places an unnecessary burden on ratepayers. In my opinion, the Commission has the opportunity to mitigate the Company's proposed rate increase by approving a longer amortization period for this deferred cost balance. If the Company's

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[75] See Direct Testimony of Keith C. Coffer, p. 24.
[76] *Id.*
[77] *Id.*
[78] *Id.*

proposed 5-year amortization period is increased to 10 years, it would save current ratepayers almost $2.4 million per year. The Company should be financially indifferent to the recovery time period, so long as the balance is included in rate base earning a full weighted average cost of capital.

Q: WHAT DO YOU RECOMMEND?

A: I recommend that the critical infrastructure deferred balance be recovered over a 10-year amortization period. This results in a reduction in the retail amount of $2.380 million, as is set forth on Exhibit No. ___(MG-2).

II. J. <u>TURBINE MAJOR MAINTENANCE</u>

Q: PLEASE DISCUSS THE COMPANY'S REQUEST FOR THE TURBINE MAJOR MAINTENANCE ACCRUAL AND RESERVE ACCOUNT.

A: DESC is requesting that the annual accrual for turbine major maintenance expense be increased by $10,616,708 from $18,435,785 to $29,052,493 annually.[79] The adjustment is based on estimated costs for the period 2021 through 2028 and includes the full recovery of $11,981,766 in projected unrecovered costs.[80] The requested increase also includes maintenance costs associated with the recently acquired Columbia Energy Center ("CEC"), as authorized by Commission Order No. 2019-393.[81]

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[79] See Direct Testimony of Keith C. Coffer, p. 20, lines 1-17.
[80] See Direct Testimony of Keith C. Coffer, p. 20, lines 13-16.
[81] Id. at 4-5.

Q: TO SUPPORT THE REQUESTED INCREASE, MR. KISSAM NOTES THAT THE CURRENT ACCRUAL IS NOT SUFFICIENT TO RECOVER THE COMPANY'S PROJECTED UNDER-RECOVERY OF TURBINE MAINTENANCE EXPENSES OF NEARLY $12 MILLION.[82] DO YOU AGREE WITH THIS ASSESSMENT?

A: No. The current accrual for major turbine maintenance has actually *decreased* the Company's regulatory asset for unrecovered maintenance costs over the last 8-year cycle. In fact, the balance in the regulatory asset account, Account No. 1823026, at the beginning of the 8-year cycle was slightly above $14 million[83] and the balance in at December 31, 2019 was $8,008,542.[84] This means the current annual accrual has been sufficient to cover annual maintenance expenses <u>*and*</u> help amortize the deferred balance.

Q: SHOULD THE CURRENT ANNUAL ACCRUAL BE INCREASED TO COVER THE ADDITIONAL NEW COSTS OF THE COLUMBIA ENERGY CENTER?

A: Yes. The Company has added the Columbia Energy Center to its generating fleet since the last rate case, and the impact of that addition should be considered in setting the level of turbine maintenance costs to be recovered from ratepayers. A review of the Company's adjustment workpapers shows that CEC accounts for nearly $37 million of turbine maintenance costs for the 8-year period from 2021 through 2028,[85] for an average annual

[82] See Direct Testimony of Keller Kissam, p. 65, lines 7-8.

[83] See Response to 4-7(b).xlsx, cell K229.
[84] See Response to ORS-1-2, Attachment 1-2 Balance Sheet and Income Statement Details.xlsx, tab Balance Sheet Comparison, cell H401.
[85] See Response to ORS-1-5, Attachment 1-5 PF Adj #22 Major Maint Accrual.xlsx, tab 2020 Accrual – Combined, sum of cells D12 - K12.

cost of $4,606,500. The current annual accrual should be increased by this amount.

Also, to make sure there are sufficient funds to amortize the existing major maintenance regulatory asset of $8,008,542[86] over the upcoming 8-year cycle, I recommend that one-eighth of this amount, $1,001,068, be added to the current annual accrual.

Q: WHAT IS THE AMOUNT OF YOUR PROPOSED ADJUSTMENT?

A: I recommend that the Company's requested major turbine maintenance expenses increase of $10,616,708 be reduced by $5,009,140. This adjustment would result in an annual *increase* in the major turbine maintenance expense of $5,607,568. This increase would cover the added maintenance costs of the Columbia Energy Center in the amount of $4,604,500 and would also provide an additional $1,001,068 for an 8-year amortization of the regulatory asset balance at December 31, 2019. This adjustment can be seen at Exhibit No.___(MG-2).

II. K. CONSTRUCTION WORK IN PROGRESS ("CWIP")

Q: WHAT AMOUNT DID DESC REQUEST FOR CONSTRUCTION WORK IN PROGRESS?

A: DESC requested $552 million for construction work in progress for the South Carolina retail jurisdiction.[87] This includes $270 million recorded at December 31, 2019 plus a pro

[86] See Response to ORS-1-2, Attachment 1-2 Balance Sheet and Income Statement Details.xlsx, tab Balance Sheet Comparison, cell H401.

[87] See Direct Testimony of Keith C. Coffer, Exhibit No.___ (KCC-2 Supplemental) Exhibit C-2, page 1 of 3, line 17, column 4.

forma adjustment of $282 million added with the estimated update of plant through September 2020, a full nine months after the end of the test year.[88]

Q: WHAT WAS THE BASIS FOR THE UPDATE THROUGH SEPTEMBER 2020?

A: The Office of Regulatory Staff agreed in a letter dated June 18, 2020 that they would be able to verify the plant additions through that date if those estimates were included in the filing.[89]

Q: DID THE COMPANY ULTIMATELY UPDATE PLANT THROUGH SEPTEMBER 30, 2020.

A: Yes. In response to ORS-8-6, the Company provided updates to several pro forma adjustments through September 30, 2020, including plant in service.

Q: WHAT IS THE AMOUNT OF CONSTRUCTION WORK IN PROGRESS ("CWIP") AT SEPTEMBER 30, 2020?

A: According to the Company's updated schedules, the amount of CWIP at September 30, 2020 is $332,821,000, which means about $220 million of the CWIP at test year was in service—in other words used and useful—by September 30, 2020.

Q: SHOULD THIS AMOUNT BE INCLUDED IN RATE BASE?

A: No. The amount included in rate base should be the balances in the Plant in Service

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[88] See Direct Testimony of Kevin R. Kochems, p. 11, lines 13-15.
[89] See Direct Testimony of Kevin R. Kochems, 11:13-15.

accounts at September 30, 2020. This is the investment that is actually used and useful for providing utility service to customers. The CWIP at September 30, 2020 should be excluded. This is the appropriate treatment of CWIP when there is a post-test-year update.

Q: HOW IS CWIP GENERALLY TREATED FOR RATEMAKING PURPOSES WHEN THE TEST YEAR IS NOT UPDATED?

A: Generally, CWIP is excluded from rate base and instead permitted to earn an "allowance for funds used during construction" (AFUDC) return until such time as these projects are completed and transferred to the Plant in Service accounts. This generally accepted ratemaking treatment preserves the integrity of the historical test year without causing economic harm to the Company.

Q: WHY IS THIS THE GENERALLY ACCEPTED TREATMENT OF CWIP?

A: Traditional ratemaking principles exclude CWIP from rate base because plant under construction is not used and useful for providing electric service to utility customers currently on the system. However, in order to allow investors an opportunity to earn a return on their invested capital, CWIP accrues an AFUDC return while the projects are under construction. When construction is completed and the facilities are dedicated to utility service, the invested capital along with its accrued return is transferred to rate base.

Q: WHAT IS THE TREATMENT OF CWIP WHEN A POST-TEST YEAR UPDATE IS ALLOWED?

A: When an update is allowed, all plant and plant-related accounts are updated. This would include plant in service, accumulated depreciation, ADIT, and depreciation expense, but it would not include CWIP. CWIP on the books at the date of the update is plant that is not in service and not *used and useful* to ratepayers.

Q: ARE YOU FAMILIAR WITH STATES THAT FOLLOW THIS APPROACH?

A: Yes. Both Nevada and Oklahoma, by law, allow post-test year updates, where known and measurable changes up to six months after test year end are allowed. In practice, this means that all plant and plant-related accounts are updated to the post-test year cutoff date, but CWIP at that point is *not allowed* in rates. Allowing all plant placed in service during the post-test year update period is favorable enough. Allowing CWIP at the end of the cutoff period would, in effect, be allowing the utility to go beyond the cutoff date for additional investment.

Q: WAS THE COMPANY'S UPDATE THROUGH SEPTEMBER 2020 SUFFICIENTLY COMPREHENSIVE?

A: No. The update did not include an update for revenues, which would generally be an essential adjustment to any ratemaking update. For example, a review of changes in revenues over the last few years shows that revenues have increased consistently over that period. Electric revenues increased by $338 million from 2017 through 2018, and $800 million from 2018 through 2019.[90] If revenues are expected to increase during the rate-

[90] See Response to ORS-1-2, Attachment 1-2 Balance Sheet and Income Statement Details.xlsx, tab Income Statement Comparison, cells F60 and I60.

effective period, a revenue adjustment should be included with any post-test year update.

Q: WHY IS A REVENUE UPDATE CRUCIAL IN THIS SITUATION?

A: When a utility goes beyond the test year to pick up increases in one area such as plant in service, it must also quantify offsetting decreases, otherwise, the rate-setting process is based on objectional piecemeal ratemaking, where cost increases are included and offsetting decreases are ignored. The largest potential offset that should be included in any post-test year analysis would be increases in revenues. In short, a utility should not be allowed to include post-test year plant investment in rates without an offsetting adjustment for revenue increases.

Q: ARE THERE REASONS FROM A POLICY PERSPECTIVE TO REJECT THE COMPANY'S PROPOSED POST-TEST YEAR CWIP ADJUSTMENT?

A: Yes. The current COVID-19 pandemic has created a situation of financial hardship for many ratepayers. This environment is not a good time to engage in alternative ratemaking approaches that help eliminate regulatory lag for the utility while adding a significant rate burden on customers. To the contrary, in this environment, I would recommend that if the Commission allows the utility to go nine months beyond the test year for plant balances, that it adhere to a strict cutoff for plant at that date and not allow a further increase for CWIP. The utility is not without recourse under this approach as it can file another rate case in two or three years if regulatory lag causes it to significantly underearn.

Q: WHAT DO YOU RECOMMEND?

A: I recommend that the Commission disallow the CWIP balances included in the Company's updated plant balances through September 2020.

Q: WHAT IS THE AMOUNT OF YOUR PROPOSED ADJUSTMENT?

A: I recommend that the Commission disallow the $332.821 million CWIP balance at September 30, 2020. This adjustment is set forth at Exhibit No.___ (MG-2).

III. <u>COST OF SERVICE / RATE DESIGN</u>

Q: WHAT IS THE PURPOSE OF COST OF SERVICE AND RATE DESIGN?

A: The purpose of a cost of service study is to allocate a utility's costs among the various customer classes based upon the cost to provide service to each class. Rates are then designed to collect those costs from customers. Effective rate design ensures that customers only pay for the costs they cause on the system.

Q: HOW IS A COST OF SERVICE STUDY PERFORMED?

A: Each customer class is allocated its proportional share of the total system costs based on the level of costs incurred to provide service to that class. Cost of service studies consider data from all facets of utility operations, including accounting records, engineering analyses, resource planning, load research and customer billing data. The studies relate each component of the revenue requirement to measurable characteristics, such as customer demand, energy usage, and number of customers in a class. After the costs are allocated to the classes, the revenues produced by each class are compared with the class cost levels to determine which classes are under-paying and which classes are over-paying their respective costs. From this comparison, we learn which classes need rate increases and which classes need rate decreases to bring all the classes to the same rate of return, or to ***equalized rates of return.*** When the revenues collected from each class fully cover the costs caused by that class then rates are said to be set at ***cost-of-service.*** When rates are not set at cost-of-service, then some customers are paying costs caused by other customers. We describe these over-payments and under-payments among the classes as ***inter-class subsidies.***

Q: WHY IS IT IMPORTANT TO CORRECTLY ALLOCATE COSTS TO THE INDIVIDUAL CUSTOMER CLASSES?

A: When costs are correctly allocated to the individual classes, rates can be developed to recover the actual cost of providing service to each class. These cost-based rates are equitable because customers pay only the costs incurred to serve them. Cost-based rates are also more efficient in that they ultimately tend to reduce the overall cost to the electric provider. This efficiency occurs because cost-based rates send better price signals to customers, who then make better choices in rationing their use of electricity. Conversely, rates that are not cost-based tend to promote inefficiencies. These inefficiencies occur when prices are set below cost for certain customers. These artificially lower rates tend to cause subsidized customers to increase consumption of energy based on incorrect price signals. Ultimately, the increased consumption brought about from artificially lower rates causes the utility to increase its overall cost over time to meet the increase in demand to serve subsidized customers.

Q: WHAT ARE PRICE SIGNALS AND HOW DO THEY HELP ACHIEVE IMPORTANT RATE DESIGN OBJECTIVES?

A: Price signals are the price level information communicated from energy producers to consumers in competitive energy markets. In regulated electric power markets, price levels are administratively determined by a public utility commission for each rate class. The function of a price signal is to establish the level of production at which supply and demand will match. In competitive energy markets, there is a continual dialogue between energy producers and consumers, where energy producers send cost production signals to consumers, and consumers in turn signal back to producers the prices at which they are willing or able to purchase energy.

Q: IS THE PROPER ROLE OF PRICE SIGNALS SUBSTANTIALLY DIFFERENT IN REGULATED ENERGY MARKETS?

A: No. The role of regulated price signals is ultimately the same. The Commission simply acts as an intermediary in the communication process between consumers and the utility to ensure that the utility's costs are set at just and reasonable levels. However, since price signals are communicated to each ratepayer class through filed tariffs, which are developed and implemented at discrete time intervals when there is a rate case, the communication process for regulated energy markets is not immediate. It is nevertheless important that customers of regulated utilities receive accurate price signals.

Q: WHY ARE ACCURATE PRICE SIGNALS IMPORTANT?

A: Rates for each customer class need to reflect DESC's true cost to serve each class so that consumers within each class will make energy usage decisions based upon actual costs. Otherwise, consumer demand or usage patterns will be distorted, and DESC will not have the most accurate measure of demand for purposes of resource planning.

Q: WHAT IS THE TYPICAL RELATIONSHIP BETWEEN ENERGY COSTS AND DEMAND?

A: Like most energy commodities, energy usage is somewhat elastic. As prices increase, consumers typically seek options to reduce usage or demand.

Q: WHY ARE COST-BASED RATES AND PROPER PRICE SIGNALS PARTICULARLY IMPORTANT ON THE COMPANY'S SYSTEM AT THIS TIME?

A: High utility rates put tremendous financial pressures on large, high-use customers. This problem is further exacerbated by price subsidies. When distorted price signals cause large customers to reduce energy consumption, this often means reducing productivity, shifting production to lower-cost facilities, or cutting jobs. In short, every dollar that large customers pay for electricity above the actual cost of that electricity is a dollar not available to maximize productivity, services jobs and economic growth. For this reason, the Commission should work to eliminate price subsidies to the greatest extent possible.

III. A. <u>POWER FACTOR CORRECTION</u>

Q: WHAT IS POWER FACTOR?

A: Power factor is the ratio of real power to apparent power. Power factor indicates the amount of apparent power (total current and voltage) that is actually doing the work or producing the real power. If real power equals apparent power, voltage and current are said to be "in-phase," and the resulting power factor is 100%. If real power does not equal apparent power and voltage and current are out of phase, power factor will be between 0% and 100%.

Q: WHY DO UTILITIES RECOGNIZE THAT POWER FACTOR IS IMPORTANT?

A: From the customer's perspective, the higher the power factor achieved by individual customer, the better that customer is able to operate its equipment at its rated power level without drawing excess current. From a system perspective, with customers at higher power factors, the utility can efficiently transmit and distribute more real power without having to increase the capacity of electric utility facilities. By requiring customers to maintain higher power factors, the utility can minimize the level of investment in electric facilities.

Q: WHY DOES DESC INCLUDE A POWER FACTOR CORRECTION PROVISION

IN RATE 24?

A: The Company's response to DoD/FEA-1-38 states, "The Company has used an 85% power factor for decades to promote efficient use of power, minimize transformer and line losses and reduce costs for other customers."

Q: HOW DOES THE POWER FACTOR CORRECTION REDUCE COSTS FOR CUSTOMERS?

A: The standard application of the power factor correction has the effect of increasing the billing demand for a customer by 1% for each 1% the power factor is less than the stated threshold. At DESC, for customers on Rate 24 (and Rate 23), the threshold is 85%. Thus, for a customer whose power factor is 75%, the power factor correction would increase the billing demand for the customer by 10% thus increasing the demand revenue from that customer, which in turn, reduces the demand costs to be recovered from other customers.

Q: WHY DOES THE COMPANY'S POWER FACTOR CORRECTION RESULT IN UNRECOVERED REVENUES AND SUBSIDIES BETWEEN CUSTOMERS IN THE RATE CLASS?

A: The problem in this case is that the Company's power factor correction threshold is set too low. Currently the power factor correction is only applied to customers with power factors ***less than 85%***. For a rate design with a demand charge based on kW such as Rate 24 (and Rate 23), a customer with a 95% power factor is being billed for 10% more billing kW than a customer with an 85% power factor. The goal for the fair and efficient recovery of costs should be for all customers to be as close to a 100% power factor as possible. For ratemaking purposes, all customers within a rate class should be billed based on a consistent set of billing units. Use of an 85% threshold for power factor correction allows for significant differences between customers within the class to remain uncorrected. As a result, customers with higher power factors are subsidizing customers with lower power factors.

Q: WOULD AN INCREASE IN THE POWER FACTOR CORRECTION THRESHOLD REDUCE THE AMOUNT OF SUBSIDY PROVIDED BY CUSTOMERS WITH HIGHER POWER FACTORS?

A: Yes. An increase in the power factor correction threshold from 85%—to a higher threshold of 90% or 95%—would result in a lower per-unit demand charge for the rate class. Lower power factor customers would pay a higher level of demand charges that more accurately reflects the cost of service and the subsidy currently being paid by higher power factor customers would be reduced.

Q: CAN YOU ILLUSTRATE THE FLAW IN THE COMPANY'S CURRENT POWER FACTOR CORRECTION METHOD?

A: Yes. The table below shows the impact of the cross-subsidy that can occur under the Company's current power factor correction approach:

	Customer #1	Customer #2	Difference
Peak On Peak KVA Demand	30,000	30,000	-
Power Factor	92%	85%	-7%
Billing kW	27,600	25,500	(2,100)
Summer Demand Charge - 4 Months	$ 17.55	$ 17.55	
Off Peak Demand Charge - 8 Months	$ 12.44	$ 12.44	
Annual Demand Billing	$ 4,684,272	$ 4,327,860	(356,412)

The table above compares the annual demand billing of two customers assuming the same On-Peak kVA Demand of 30,000, but with different average power factor levels—Customer-1, with a power factor of 92%, and Customer-2, with a power factor of 85%. Customer-1 has a Billing kW of 27,600 kW,[91] while Customer-2 has Billing Kw of 25,500 kW.[92] The difference in Billing kW attributable to the power factor is 2,100 kW.[93] This example illustrates that on an annual basis the estimated difference in demand charges paid between Customer-1 and Customer-2 would be $356,412. This is a 7.6% difference in the demand charge paid between the two customers. Under the Company's threshold, this discrepancy would ***not*** be corrected because the power factor of Customer-2 is 85% (not ***less than*** 85%). As a result, the Customer-2 in this example would receive a significant subsidy at the expense of Customer-1. This discrepancy (and thus the inappropriate cross-subsidy) could be reduced if the threshold for power factor correction would apply to customers with less than 90% (rather than 85%).

[91] Customer 1 = (30,000 kVA Demand x 92% = 27,600kW).
[92] Customer 2 = (30,000 kVA Demand x 85% = 25,500kW).
[93] (Customer-1 27,600 kW) – (Customer-1 25,500 kW) = 2,100 kW.

Q: CAN YOU QUANTIFY THE TOTAL IMPACT ON THE CLASS OF INCREASING THE POWER FACTOR CORRECTION THRESHOLD TO A SPECIFIC LEVEL?

A: No. DESC's current rate filing does not include sufficient data to calculate the impact to the rate class or to the individual customers within the rate class.

Q: HAS DESC CONDUCTED A FORMAL ANALYSIS OF RAISING ITS POWER FACTOR CORRECTION THRESHOLD?

A: In response to DoD/FEA-1-39, the Company states:

> While the Company has not conducted a formal analysis of the impact of raising its power factor correction threshold to 90%, such a request would likely impose greater costs on its customers, either through required technology/process/equipment improvements (such as capacitors) required at customer facilities, or through increased billing charges for certain customers whose current facilities receive electric service from DESC and whose usage falls between 85% and 90% power factor.

Q: IS IT REASONABLE TO EXPECT THAT THERE ARE NUMEROUS CONSUMERS SERVED ON RATE 24 THAT HAVE POWER FACTORS LESS BETWEEN 85% AND 90%?

A: Yes. Based on DESC's response it is reasonable to expect that there are customers whose power factor is between 85% and 90%. There are several customers served on Rate 24 that are very large. If those customers have low power factors, a correction to 90% could have a significant impact on billing units.

Q: OTHER THAN INCREASING THE POWER FACTOR THRESHOLD, IS THERE

ANOTHER METHOD TO RESOLVE THE POWER FACTOR CORRECTION ISSUE?

A: Yes. Another way to resolve the issue is to redesign Rate 24 using KVA Demand instead of kW Demand as the billing unit, which would cause billing units for all customers to be consistent and would eliminate the need for a power factor correction. Such a rate redesign would reflect a higher level of demand billing units and lower per-unit rate.

Q: WHAT WOULD BE THE IMPACT ON INDIVIDUAL CUSTOMERS OF REDESIGNING RATE 24 USING KVA DEMAND AS THE BILLING UNIT?

A: Using KVA demand as the billing unit would cause the billings for customers with power factors closer to 85% to increase while billings for customers closer to 100% would decrease.

Q: DOES DESC HAVE THE ABILITY TO BILL BASED ON KVA DEMAND?

A: Yes. The Company currently uses KVA billing for both the General Service and Medium rate classes but not for Large customers, where it is needed most. With KVA billing, the General Service and Medium rates have no Power Factor adjustment clause.

Q: WHAT IS YOUR RECOMMENDATION FOR ADDRESSING THE POWER FACTOR CORRECTION ISSUE?

A: The most appropriate solution would be to redesign the Large General Service rates using kVA demand. However, the impact of this change on individual customers may be too significant to implement in one step. As an alternative, I would recommend the Company implement a gradual approach to eliminate the intra-class subsidy resulting from the differences in power factor by increasing the power factor threshold to 90%. In ***conjunction with*** raising the power factor threshold to 90%, the Commission should require DESC to redesign Rate 24 (and Rate 23) to recognize the additional Billing kW that results from application of the raised threshold. This would provide a reasonable first step which could be followed in subsequent filings with a further increase in the threshold or a full redesign based on using kVA demand.

III. B. <u>RATE 23 AVAILABILITY</u>

Q: WHAT DOES THE AVAILABILITY CLAUSE OF RATE 23 STATE?

A: The Availability Clause of Rate 23 states, " This rate is available to any customer classified in the major industrial group of manufacturing with 10-14 or 20-39 as the first two digits of the Standard Industrial Classification ("SIC"), or 21 or 31-33 as the first two digits of the six digit North American Industry Classification System ("NAIC") using the Company's standard service for power and light requirements and having a contract demand of 1,000 kW or over. It is not available for resale service."

Q: DO ANY OF DESC'S OTHER RATE SCHEDULES HAVE AN AVAILABILITY CLAUSE THAT IS SIMILAR TO RATE 23?

A: No. DESC's other rate schedules have availability clauses that reflect the type of service being provided by the Company and/or the size of the load to be served.

Q: IS THE AVAILABILITY CLAUSE OF RATE 23 TYPICAL?

A: No, not in my experience. I am not aware of another example of a tariff which limits its availability based on SIC codes or NAIC codes.

Q: WHAT IS TYPICALLY THE CRITERIA FOR PROVIDING SERVICE TO CUSTOMERS ON A SPECIFIC TARIFF?

A: Tariffs are typically available to customers with similar usage characteristics, utilizing similar electric facilities of the utility or with similar costs of providing service. The typical availability clause reflects the type of service being provided with metrics such as size or load factor to distinguish the type of load.

Q: DOES A SIC CODE OR NAIC CODE ENSURE A SPECIFIC ELECTRIC USAGE PATTERN SUCH AS HIGH LOAD FACTOR OR NON-WEATHER SENSITIVE.

A: No. There can be significant variations in consumption patterns among customers within a similar industry.

Q: DO YOU AGREE WITH THE COMPANY'S USE OF THE RATE 23 AVAILABILITY CLAUSE?

A: No. In my view, the Rate 23 Availability Clause is subjective and unduly discriminatory.

Q: HAS DESC PROVIDED ITS REASONING FOR LIMITING THE RATE 23

AVAILABILITY BASED ON SIC AND NAIC CODES?

A: Yes. In response to DoD/FEA-1-34, the Company states its rational from the 1993 Order approving the Rate 23 as follows:

> Industrial customers devote large amounts of their electric usage to production which is not weather sensitive. Accordingly, they have a much better load factor – that is, their year-round use is much higher compared to their contribution to summer peak. Non-general load is generally more weather sensitive. Non-industrial customers show much higher increases in demand during summer months when the weather is hot. Accordingly, they have much more ability to control peak contribution by load shifting. Moving these customers off Rate 23 to Time-of-Use will assist in conservation efforts. Non-Industrial accounts are proposed to be moved to Rate 24 – Large General Service Time-of-Use. However, these customers will be able to choose from any of the other rates available to them. This change will provide economic incentives for these non-industrial customers to engage in load management techniques that will be cost beneficial and increase energy efficiency.[94]

Q: BASED ON THE COMPANY'S REASONING, WHAT TYPE OF LOADS ARE INTENDED TO BE SERVED ON RATE 23?

A: The Company indicates that it is targeting large industrial customers with constant consumption during the year – in effect, customers with ***high load factors*** who are not weather sensitive.

Q: WHAT IS YOUR RECOMMENDATION REGARDING THE AVAILABILITY OF RATE 23?

A: I recommend that the Commission require DESC to revise the availability provision of Rate 23 to read, "This rate is available to any customer using the Company's standard

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[94] See response to DOD/FEA-1-34.

service for power and light requirements having a contract demand of 1,000 kW or over and an average annual load factor of 60% or higher based on On-Peak CP demand . . . This rate is not available for resale service." Revising the availability provision in this manner allows weather sensitive customers with sufficiently high load factors to take advantage of this rate.

IV. COST OF CAPITAL

Q: DOES DOD/FEA PROPOSE COST OF CAPITAL RECOMMENDATIONS?

A: Yes. Dr. Zhen Zhu provides testimony on behalf of DoD/FEA regarding cost of capital issues. The impacts of his cost of capital recommendations on the revenue requirement are set forth in Exhibit No.___ (MG-2).

V. CONCLUSION

Q: DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A: Yes, it does.

EXHIBIT NO. ____ (MG-1)

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EDUCATION:

Juris Doctor Degree, With Honors, Oklahoma City University Law School, 1997
Post Graduate Hours in Accounting, Finance and Economics, 1984-85:
University of Texas at Arlington; University of Texas at Pan American;
Stephen F. Austin State University
Bachelor of Arts Degree, University of Oklahoma, 1978

CREDENTIALS:

Member Oklahoma Bar Association, 1997, License No. 017629
Certified Public Accountant in Oklahoma, 1992, Certificate No. 11707-R
Certified Public Accountant in Texas, 1986, Certificate No. 48514

WORK HISTORY:

GARRETT GROUP CONSULTING, INC. – Regulatory Consulting Practice (1996 - Present) Participates as a consultant and expert witness in electric utility, natural gas distribution company, and natural gas pipeline matters before regulatory agencies in rate case proceedings to determine just and reasonable rates. Reviews management decisions of regulated utilities regarding the reasonableness of prices paid for electric plant, gas plant, purchased power, renewable energy projects, natural gas supplies and transportation, and coal supplies and transportation. Participates in regulatory proceedings to restructure the electric and natural gas utility industries. Participates as an Instructor at NMSU Center for Public Utilities and as a Speaker at NARUC Staff Subcommittee on Accounting and Finance.

OKLAHOMA CORPORATION COMMISSION - Coordinator of Accounting and Financial Analysis (1991 - 1994) Planned and supervised the audits of major public utility companies doing business Oklahoma for the purpose of determining revenue requirements. Presented both oral and written testimony as an expert witness for Staff in defense of numerous accounting and financial recommendations related to cost-of-service based rates. Audit work and testimony covered all areas of rate base and operating expense. Supervised, trained and reviewed the audit work of numerous Staff CPAs and auditors. Promoted from Supervisor of Audits to Coordinator in 1992.

FREEDOM FINANCIAL CORPORATION - Controller (1987 - 1990) Responsible for all financial reporting including monthly and annual financial statements, cash flow statements, budget reports, long-term financial planning, tax planning and personnel development. Managed the General Ledger and Accounts Payable departments and supervised a staff of seven CPAs and accountants. Reviewed all subsidiary state and federal tax returns and facilitated the annual independent financial audit and all state or federal tax audits. Received promotion from Assistant Controller in September 1988.

SHELBY, RUCKSDASHEL & JONES, CPAs - Auditor (1986 - 1987) Audited the financial statements of businesses in the state of Texas, with an emphasis in financial institutions.

Previous Experience Related to Cost-of-Service, Rate Design, Pricing and Energy-Related Issues

1. **Dominion Energy South Carolina, 2020 (South Carolina), (Docket No. 2020-125-E) –** Participating as an expert witness on behalf of DOD/FEA in DESC's rate case application, sponsoring testimony to address various revenue requirement, rate design and tax issues.

2. **Cascade Natural Gas, 2020 (Washington), (NG-UG-200568) –** Participating as an expert witness on behalf of Public Counsel in Cascade's rate case application, sponsoring testimony to address various revenue requirement and tax issues.

3. **Nevada Power Company, 2020 (Nevada) (Docket No. 20-06003) –** Participating as an expert witness on behalf of Bureau of Consumer Protection ("BCP") before the Nevada Public Utility Commission to address various revenue requirement issues in the case.

4. **El Paso Electric Company, 2020 (New Mexico), (Docket RC-20-00104-UT) –** Participating as an expert witness on behalf of the City of Las Cruces and Dona Ana county in EPE's rate case application, sponsoring testimony to address various revenue requirement and tax issues.

5. **Oklahoma Gas and Electric Company, 2020 (Oklahoma), (Cause No. PUD 202000021) –** Participating as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in OG&E's Grid Enhancement Plan application. Sponsoring testimony to address the utility's proposed cost recovery mechanism and cost of service allocations.

6. **Philadelphia Gas Works, 2020 (Pennsylvania), (Docket No. R-2020-3017206)** – Participating expert witness on behalf of Office of Consumer Advocate ("OCA") before the Pennsylvania Public Utility Commission to address various revenue requirement issues in PGW's rate case.

7. **Atmos MidTex (Texas), 2020 (Texas), (Dallas Annual Rate Review) –** Participating as an expert witness on behalf of the City of Dallas before the Texas Railroad Commission in Atmos's Dallas Annual Rate Review ("DARR") proceeding. Sponsoring recommendations on various revenue requirement issues.

8. **Southwest Gas Corporation, 2020 (Nevada) (Docket No. 20-02023)** – Participated as an expert witness on behalf of Bureau of Consumer Protection ("BCP") before the Nevada Public Utility Commission to address various revenue requirement issues.

9. **El Paso Electric Company, 2019 (Texas), (Docket No. 49849) –** Participating as an expert witness on behalf of the City of El Paso in the merger of El Paso Electric Company with Sun Jupiter Holdings LLC and IIF US Holdings 2 LLP to provide recommendations to the Texas Public Utility Commission regarding the treatment of tax issues in the proposed merger agreement.

10. **Nevada Senate Bill 300 Rulemaking, 2019 (Nevada), (Docket No. 19-069008) –** Participating as an expert witness on behalf of the Southern Nevada Gaming Group before the Nevada PUC to assist with the development of alternative ratemaking regulations under SB 300.

11. **Entergy Arkansas, 2019 (Arkansas), (Docket No**. 19-020-TF) – Participating as an expert witness on behalf of the Arkansas industrial consumer group to review EAI's application to allocate its perceived under-recovery of off-system sales margins to Arkansas customers.

12. **Public Service Company of Oklahoma, 2019 (Oklahoma) (Cause No. PUD 201900201) –**

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Participating as an expert witness on behalf of OIEC before the OCC in AEP/PSO's application for approval for the cost recovery of selected wind facilities.

13. **Oklahoma Gas & Electric Co., 2019 (Arkansas) (Docket No. 18-046-FR)** – Participating as an expert witness on behalf of the Arkansas River Valley Energy Consumers ("ARVEC")[1] before the Arkansas Public Service Commission in OG&E's Formula Rate Plan application to provide testimony on various revenue requirement, cost of service and rate design issues.

14. **Southwestern Public Service Co., ("SPS") 2019 (Texas), (Docket No. 49831) –** Participating as an expert witness on behalf of the Alliance of Xcel Municipalities ("AXM") in the SPS general rate case application to provide testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsor the AXM Accounting Exhibits.

15. **Southwestern Electric Power Company, 2019 (Arkansas), (Docket No. 19-008-U)** – Participated as an expert witness on behalf of Western Arkansas Large Energy Consumers ("WALEC") before the Arkansas Public Service Commission in SWEPCO's rate case to address various revenue requirement and rate design issues.

16. **Anchorage Municipal Light and Power and Chugach Electric Association, 2019 (Alaska), (Docket No. U-19-020) –** Participating as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony on pending acquisition of ML&P by Chugach to address the proposed acquisition premium and other issues associated with the public interest.

17. **Sierra Pacific Power Company, 2019 (Nevada), (Docket No. 19-06002)** – Participated as an expert witness on behalf of Bureau of Consumer Protection ("BCP") before the Nevada Public Utility Commission to address various revenue requirement issues.

18. **Air Liquide Hydrogen Energy U.S., 2019 (Nevada), (704B Exit Application, Docket No. 19-02002)** – Participated as an expert witness on behalf of Air Liquide before the Nevada PUC. Sponsoring written and oral testimony in Air Liquide's application to purchase energy and capacity from a provider other than NV Energy.

19. **Empire District Electric Company, 2019 (Oklahoma), (Cause No. PUD 201800133)** – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in Empire's general rate case to address various revenue requirement, rate design and tax issues.

20. **Indiana Michigan Power, 2019 (Indiana), (Docket No. 45235) –** Participating as an expert witness on behalf of the Office of Utility Consumer Counselor in I&M's rate case application, sponsoring testimony to address various revenue requirement and tax issues.

21. **Puget Sound Energy, 2019 (Washington), (Docket No. 190529-30)** – Participating as an expert witness on behalf of Public Counsel in PSE's rate case application, sponsoring testimony to address various revenue requirement and tax issues.

22. **Anchorage Municipal Light and Power, 2019 (Alaska), (Docket No. U-18-102) –** Participating as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony on the ratemaking treatment of ML&P's acquired interest in the Beluga

[1] ARVEC is an association of industrial manufacturing facilities in northwest Arkansas.

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River Unit gas field with ratepayer funds.

23. **Oklahoma Gas and Electric Company, 2019 (Oklahoma), (Cause No. PUD 201800140) –** Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in OG&E's General Rate Case application. Sponsoring testimony to address the utility's overall revenue requirement and rate design proposals.

24. **Cascade Natural Gas, 2019 (Washington) (Docket No. 190210)** – Participated as an expert witness on behalf of Public Counsel in Cascade's rate case application. Sponsoring testimony to address various revenue requirement and tax issues.

25. **CenterPoint Energy Houston Electric, 2019 (Texas) (Docket No. 49421)** – Participated as an expert witness on behalf of City of Houston before the Public Utility Commission of Texas in CenterPoint Energy's rate case application to provide testimony on various revenue requirement issues.

26. **Oklahoma Gas & Electric Co., 2018 (Arkansas) (Docket No. 18-046-FR** – Participated as an expert witness on behalf of the Arkansas River Valley Energy Consumers ("ARVEC")[2] before the Arkansas Public Service Commission in OG&E's Formula Rate Plan application to provide testimony on various revenue requirement, cost of service and rate design issues.

27. **Southwest Gas Corporation, 2018 (Nevada) (Docket No. 18-05031) –** Participated as an expert witness on behalf of Bureau of Consumer Protection ("BCP") before the Nevada Public Utility Commission to address various revenue requirement issues.

28. **Puget Sound Energy, 2018 (Washington) (Docket No. UE 18089) -** Participated as an expert witness on behalf of Public Counsel in PSE's Emergency Rate Relief proceeding. Sponsoring testimony to address the application itself and various revenue requirement and TCJA issues.

29. **Public Service Company of Oklahoma, 2018 (Oklahoma) (Cause No. PUD 201800097) –** Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various revenue requirement, cost of service and rate design issues.

30. **Entergy Texas Inc., 2018 (Texas) (PUC Docket No. 48371) –** Participated as an expert witness on behalf of the Cities in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

31. **Atmos Energy Corp., Mid-Tex Division, 2018 (Texas) (Docket No. GUD No. 10779)** – Participated as an expert witness on behalf of the Atmos Texas Municipalities to review the utility's requested revenue requirement including TCJA adjustments.

32. **CenterPoint Energy Houston Electric, LLC, 2018 (Texas) (Docket No. 48226) –** Participated as an expert witness on behalf of City of Houston before the Public Utility Commission of Texas in CenterPoint Energy's application for approval to amend its distribution cost recovery factor (DCRF) to address the utility's treatment of the Tax Cuts and Jobs Act of 2017 ("TCJA").

33. **NV Energy, 2018 (Nevada) (Docket No. 17-10001) –** Participated as an expert witness on behalf of the Energy Choice Initiative ("ECI") before the Governor's Committee on Energy Choice, in an

[2] ARVEC is an association of industrial manufacturing facilities in northwest Arkansas.

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investigatory docket of an Issue of Public Importance Regarding the Pending Energy Choice Initiative and the Possible Restructuring of Nevada's Energy Industry.

34. **Southwestern Electric Power Company, 2018 (Texas) (PUC Docket No. 48233) –** Participated as an expert witness on behalf of Cities Advocating Reasonable Deregulation ("CARD Cities") before the Texas Public Utility Commission in SWEPCO's application to implement bae rate reductions as result of the Tax Cuts and Jobs Act of 2017 ("TCJA").

35. **Oncor Electric Delivery Company (Texas), 2018 (PUC Docket No. 48325)** – Participated as an expert witness before the Texas Public Utility Commission in Oncor's application for authority to decrease rates based on the Tax Cuts and Jobs Act of 2017 ("TCJA").

36. **Public Service Company of Oklahoma ("PSO") (Oklahoma), 2018 (Cause No. PUD 201800019)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's application regarding ADIT under the Tax Cuts and Jobs Act of 2017 ("TCJA").

37. **Oklahoma Natural Gas Company, 2018 (Cause No. PUD 201800028)** – Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission in ONG's Performance Based Rate Change Tariff, to address issues involving the impacts of the Tax Cuts and Jobs Act of 2017 ("TCJA").

38. **Oklahoma Gas & Electric Co. (Arkansas), 2018 (Docket No. 18-006-U –** Participated as an expert on behalf of the Arkansas River Valley Energy Consumers ("ARVEC") before the Arkansas Public Service Commission in the matter of an Investigation of the Effect on Revenue Requirements Resulting from Changes to Corporate Income Tax Rates under the Tax Cuts and Jobs Act of 2017 ("TCJA").

39. **Texas Gas Service, 2018** – Participated as a consulting expert on behalf of the City of El Paso regarding implementation of rate changes related to the Tax Cuts and Jobs Act of 2017 ("TCJA").

40. **Sierra Pacific Power Company (Nevada), 2018 (Docket No. 18-02011 and 18-02015)** – Participated as an expert witness on behalf of the Northern Nevada Utility Customers[3] before the Nevada PUC in SPPC's application related to the Tax Cuts and Jobs Act of 2017 ("TCJA").

41. **Nevada Power Company (Nevada), 2018 (Docket No. 18-02010 and 18-02014)** – Participated as an expert witness on behalf of the Southern Nevada Gaming Group before the Nevada PUC in NPC's application related to the Tax Cuts and Jobs Act of 2017 ("TCJA").

42. **Public Service Company of Oklahoma ("PSO") (Oklahoma), 2017 (Cause No. PUD 201700572)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's application to examine the impacts of the Tax Cuts and Jobs Act of 2017 ("TCJA").

43. **Empire District Electric Company ("EPE") (Oklahoma), 2018 (Cause No. PUD 201700471) –** Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in Empire's application to add 800MW of wind. Sponsoring testimony to address the various ratemaking and tax issues.

44. **Oklahoma Gas and Electric Company ("OG&E"), (Oklahoma), 2018 (Cause No. PUD**

[3] The Northern Nevada Utility Consumers is a group of large commercial and industrial customers in the SPPC service territory.

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201700496) – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in OG&E's General Rate Case application. Sponsoring testimony to address the utility's overall revenue requirement and rate design proposals.

45. **Public Service Company of Oklahoma ("PSO") (Oklahoma), 2017 (Cause No. PUD 201700276)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's Wind Catcher case to provide testimony on various ratemaking and tax issues.

46. **Southwestern Public Service Co. ("SPS") (Texas), 2017 (PUCT Docket No. 47527) –** Participating as an expert witness on behalf of the Alliance of Xcel Municipalities ("AXM") in the SPS general rate case application to provide testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsor the AXM Accounting Exhibits.

47. **Southwestern Electric Power Company, ("SWEPCO") (Texas), 2017 (PUC Docket No. 47461) –** Participated as an expert witness on behalf of Cities Advocating Reasonable Deregulation ("CARD Cities") before the Texas Public Utility Commission in SWEPCO's Wind Catcher case proceeding to provide testimony on various ratemaking and tax issues.

48. **Atmos MidTex (Texas), 2017 (Docket No. 10640) –** Participated as an expert witness on behalf of the City of Dallas before the Texas Railroad Commission in Atmos's Dallas Annual Rate Review ("DARR") proceeding. Sponsoring testimony on various revenue requirement issues.

49. **Avista Utilities (Washington), 2017 (Docket Nos. UE-170485/UG-170486)** – Participated as an expert witness on behalf of Public Counsel in Avista's general rate case proceeding. Sponsoring testimony to address various revenue requirement issues and Avista's requested attrition adjustments.

50. **Nevada Power Company (Nevada), 2017 (Docket No. 17-06003)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC in NPC's general rate case proceeding. Sponsoring testimony on various revenue requirement, depreciation, and rate design issues.

51. **Anchorage Municipal Light and Power (Alaska), 2017 (Docket No. U-17-008) –** Participating as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony in ML&P's General Rate Case on various revenue requirement and rate design issues.

52. **Public Service Company of Oklahoma (Oklahoma), 2017 (Cause No. PUD 201700151)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various revenue requirement and rate design issues.

53. **Oncor Electric Delivery Company (Texas), 2017 (PUC Docket No. 46957)** – Participated as an expert witness on behalf of the Steering Committee of Cities before the Texas Public Utility Commission in Oncor's General Rate Case proceeding to provide testimony on various revenue requirement issues.

54. **EverSource (Massachusetts), 2017 (DPU Docket No. 17-05) –** Participated as an expert witness before the Massachusetts Department of Public Utilities EverSource's General Rate Case application on behalf of Energy Freedom Coalition of America to provide testimony to address various revenue requirement issues.

55. **El Paso Electric Company (Texas), 2017 (PUC Docket No. 46831)** – Participated as an expert

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witness on behalf of the City of El Paso before the Texas Public Utility Commission in El Paso's General Rate Case proceeding to provide testimony on various revenue requirement issues.

56. **Atmos Pipeline Texas (Texas), 2017 (Docket No. 10580)** – Participated as an expert witness on behalf of the City of Dallas before the Texas Railroad Commission in APT's General Rate Case application, sponsoring testimony to address various revenue requirement proposals.

57. **Empire District Electric Company (Oklahoma), 2017 (Cause No. PUD 201600468) –** Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in Empire's General Rate Case application. Sponsoring testimony to address the utility's overall revenue requirement and rate design proposals.

58. **Caesars Enterprise Service, LLC (Nevada), 2016 (704B Exit Application)** – Participated as an expert witness on behalf of Caesars before the Nevada PUC. Sponsoring written and oral testimony in Caesar's application to purchase energy and capacity from a provider other than Nevada Power.

59. **Southwestern Electric Power Company (Texas), 2016 (PUC Docket No. 46449) –** Participated as an expert witness on behalf of Cities Advocating Reasonable Deregulation ("CARD Cities") before the Texas Public Utility Commission in SWEPCO's general rate case proceeding to provide testimony on various revenue requirement issues.

60. **CenterPoint Texas, 2016 (Docket No. 10567) –** Participated as an expert witness on behalf of City of Houston before the Texas Railroad Commission in CenterPoint's general rate case application, sponsoring testimony to address the utility's overall revenue requirement and various rate design proposals.

61. **Entergy Texas, Inc., 2016 (Docket No. 46357) –** Participated as an expert witness on behalf Cities Served by Applicant before the Texas PUC in ETI's application to amend its Transmission Cost Recovery Factor.

62. **Anchorage Municipal Light and Power, 2016 (Docket No. U-16-060) –** Participated as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony on the ratemaking treatment of ML&P's acquired interest in the Beluga River Unit gas field with ratepayer funds.

63. **Arizona Public Service Company, 2016 (Docket No. E-01345A-16-0036)** – Participated as an expert witness before the Arizona Corporation Commission in APS's General Rate Case application on behalf of Energy Freedom Coalition of America to provide written and oral testimony to address various revenue requirement issues.

64. **Oklahoma Gas & Electric Co. (Arkansas), 2016 (Docket No. 16-052-U** – Participated as an expert witness on behalf of the Arkansas River Valley Energy Consumers ("ARVEC")[4] before the Arkansas Public Service Commission in OG&E's general rate case application to provide testimony on various revenue requirement, cost of service and rate design issues.

65. **Sierra Pacific Power Company (Nevada), 2016 (Docket No. 16-06006) –** Participated as an expert witness on behalf of the Northern Nevada Utility Customers[5] before the Nevada PUC in SPPC's

[4] ARVEC is an association of industrial manufacturing facilities in northwest Arkansas.
[5] The Northern Nevada Utility Consumers is a group of large commercial and industrial customers in the SPPC service territory.

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general rate case proceeding. Sponsored testimony on various revenue requirement, depreciation, and rate design issues.

66. **Tucson Electric Power, 2016 (Docket No. E-01933A-15-0322)** – Participated as an expert witness before the Arizona Corporation Commission in TEP's General Rate Case application, on behalf of Energy Freedom Coalition of America providing written and oral testimony to address the utility's cost of service study and rate design proposals.

67. **Texas Gas Service, 2016 (Docket No. 10506)** – Participated as an expert witness on behalf of El Paso before the Texas Railroad Commission in TGS's General Rate Case application, sponsoring testimony to address the utility's overall revenue requirement and various rate design proposals.

68. **Texas Gas Service, 2016 (Docket No. 10488)** – Participated as an expert witness on behalf of South Jefferson County Service Area ("SJCSA") before the Texas Railroad Commission in TGS's General Rate Case application, sponsoring testimony to address the utility's overall revenue requirement and various rate design proposals.

69. **Oklahoma Gas and Electric Company, 2016 (Cause No. PUD 201500273)** – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in OG&E's General Rate Case application. Sponsoring testimony to address the utility's overall revenue requirement and rate design proposals.

70. **Oklahoma Gas & Electric Company, 2016 (Cause No. PUD 201500273)** – Participated as an expert witness on behalf of The Alliance for Solar Choice ("TASC") before the Oklahoma Corporation Commission to address OG&E's proposed Distributed Generation ("DG") rates for solar DG customers.

71. **Anchorage Municipal Light and Power, 2016 (Docket No. U-13-097) –** Participated as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony on rates and tariffs proposed for customer-owned combined heat and power plant generation.

72. **Oklahoma Natural Gas Company, 2015 (Cause No. PUD 201500213)** – Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission in ONG's General Rate Case application. Sponsored testimony to address the utility's overall revenue requirement and rate design proposals.

73. **Oklahoma Gas & Electric Company, 2015 (Cause No. PUD 201500274)** – Participated as an expert witness on behalf of The Alliance for Solar Choice ("TASC") before the Oklahoma Corporation Commission to address OG&E's proposed Distributed Generation ("DG") rates for solar DG customers.

74. **Nevada Power Company, 2015** (Docket No. 15-07004) – Participated as an expert witness on behalf of the Southern Nevada Hotel Group ("SNHG")[6] before the Nevada PUC. Sponsoring written and oral testimony in NPC's 2015 Integrated Resource Plan to provide analysis of the On Line transmission line allocation, the Siverhawk plant acquisition, and the Griffith contract termination.

75. **Oklahoma Gas & Electric Company, 2015 (Docket No. 15-034-U)** – Participated as an expert

[6] The Southern Nevada Hotel Group is comprised of Boyd Gaming, Caesars Entertainment, MGM Resorts, Station Casinos, Venetian Casino Resort, and Wynn Las Vegas.

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witness on behalf of the Arkansas River Valley Energy Consumers ("ARVEC") before the Arkansas Public Service Commission in OG&E's Act 310 application to implement a rider to recover environmental compliance costs.

76. **MGM Resorts, LLC, 2015** (Docket No. 15-05017) – Participated as an expert witness on behalf of the MGM Resorts, LLC before the Nevada PUC. Sponsoring written and oral testimony in MGM's application to purchase energy and capacity from a provider other than Nevada Power.

77. **Entergy Arkansas, 2015 (Docket No. 15-015-U) –** Participated as an expert witness on behalf of the Hospital and Higher Education Group ("HHEG") an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in Entergy's general rate case to provide testimony on various revenue requirement issues.

78. **Public Service Company of Oklahoma, 2015 (Cause No. PUD 201500208)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various cost-of-service issues and on the utility's overall revenue requirement and rate design proposals.

79. **Nevada Power Company, 2014** (Docket No. 14-05003) – Participated as an expert witness on behalf of the Southern Nevada Hotel Group ("SNHG") before the Nevada PUC. Sponsored written and oral testimony in NPC environmental compliance case, called the Emissions Reduction and Capacity Replacement case. The main focus of our testimony was our recommendation to eliminate the $438M Moapa solar project from the compliance plan.

80. **Nevada Power Company, 2014** (Docket No. 14-05004) – Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC to sponsor written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

81. **Oklahoma Gas and Electric Co., 2014 (Cause No. PUD 201400229)** – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") in OG&E's Environmental Compliance and Mustang Modernization Plan before the Oklahoma Corporation Commission to provide testimony addressing the economics and rate impacts of the plan.

82. **Sourcegas Arkansas, Inc., 2014 (Docket No. 13-079-U)** Participated as an expert witness on behalf of the Hospital and Higher Education Group ("HHEG"), an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in SGA's general rate case to provide testimony on various revenue requirement issues.

83. **Anchorage Municipal Light and Power, 2014 (Docket No. U-13-184) –** Participated as an expert witness before the Alaska Regulatory Utility Commission on behalf of Providence Health and Services to provide testimony on various revenue requirement and cost of service issues.

84. **Public Service Company of Oklahoma, 2014 (Cause No. PUD 201300217)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various cost-of-service issues and on the utility's overall revenue requirement and rate design proposals.

85. **Entergy Texas Inc., 2013 (PUC Docket No. 41791) –** Participated as an expert witness on behalf of

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the Cities[7] in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

86. **MidAmerican/NV Energy Merger, 2013 (Docket No. 13-07021) –** Participated as an expert witness on behalf of the Southern Nevada Hotel Group ("SNHG") before the Nevada PUC. Sponsored testimony to address various issues raised in the proposed acquisition of NV Energy by MidAmerican Energy Holdings Company, including capital structure and acquisition premium recovery issues.

87. **Entergy Arkansas, 2013 (Docket No. 13-028-U) –** Participated as an expert witness on behalf of the Hospital and Higher Education Group ("HHEG") an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in Entergy's general rate case to provide testimony on various revenue requirement issues.

88. **Sierra Pacific Power Company, 2013 (Docket No. 13-06002) –** Participated as an expert witness on behalf of the Northern Nevada Utility Customers[8] before the Nevada PUC in SPPC's general rate case proceeding to provide testimony on various cost of service and revenue requirement issues. Sponsored written and oral testimony in the depreciation phase, the revenue requirement phase and the rate design phase of these proceedings.

89. **Gulf Power Company, 2013 (Docket No. 130140-EI) –** Participated as an expert witness on behalf of the Office of Public Counsel before the Florida Commission in Gulf Power's general rate case proceeding to provide testimony on various revenue requirement issues.

90. **Public Service Company of Oklahoma, 2013 (Cause No. PUD 201200054) –** Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission ("OCC") to provide testimony in PSO's application seeking Commission approval of its settlement agreement with EPA.

91. **Southwestern Electric Power Company, 2012 (PUC Docket No. 40443) –** Participated as an expert witness on behalf of Cities Advocating Reasonable Deregulation ("CARD Cities") before the Texas Public Utility Commission in SWEPCO's general rate case proceeding to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

92. **Doyon Utilities, 2012 Alaska Rate Case** (Docket No. TA7-717) – Participated as an expert witness consultant on behalf of the Department of Defense to provide expert testimony in twelve rate case reviews for the utility systems of Fort Wainwright, Fort Greely and Joint Base Elmendorf-Richardson before the Regulatory Commission of Alaska.

93. **University of Oklahoma, 2012** – Participated as an expert witness on behalf of the University of Oklahoma to provide expert testimony on various revenue requirement issues in the University's general rate case with the Corix Group, which provides utility services to the University.

94. **Public Service Company of Oklahoma, 2012 (Cause No. PUD 201200079) –** Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission to provide expert testimony addressing the utility's request to earn additional compensation on a 510MW purchased power agreement with Exelon

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[7] The Cities include Beaumont, Conroe, Groves, Houston, Huntsville, Orange, Navasota, Nederland, Pine Forest, Pinehurst, Port Arthur, Port Neches, Rose City, Shenandoah, Silsbee, Sour Lake, Vidor, and West Orange.
[8] The Northern Nevada Utility Consumers is a group of large commercial and industrial customers in the SPPC service territory.

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95. **Centerpoint Energy Texas Gas, 2012 (Docket No.** GUD 10182) – Participated as an expert witness on behalf of the Steering Committee of Cities before the Texas Railroad Commission to provide expert testimony on various revenue requirement issues.

96. **Entergy Texas Inc., 2012 (PUC Docket No. 39896) –** Participated as an expert witness on behalf of the Cities in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

97. **Oklahoma Natural Gas Company, 2012 (Cause No. PUD 2012-029)** – Participated as an expert witness on behalf of the OIEC before the OCC in ONG's Performance Based Rate ("PBR") application seeking Commission approval of a requested rate increase based upon formula results for 2011.

98. **University of Oklahoma, 2012** – Assisted the University of Oklahoma with an audit of the costs associated with its six utility operations and its contract with the Corix Group to provide utility services to the university.

99. **Oklahoma Gas and Electric Company, 2012 (Cause No. PUD 2011-186)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking Commission approval of a special contract with Oklahoma State University and a wind energy purchase agreement in connection therewith.

100. **Empire Electric Company, 2011, (Cause No. PUD 11-082)** – Participated as an expert witness on behalf of Enbridge before the OCC in Empire's rate case to provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.

101. **Nevada Power Company, 2011, (Docket No. 11-04010) -** Participated as an expert witness on behalf of the Southern Nevada Hotel Group ("SNHG") before the Nevada PUC. Sponsored written and oral testimony to address proposed changes to the Company's customer deposit rules.

102. **Nevada Power Company, 2011, (Docket No. 11-06006) -** Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

103. **Public Service Company of Oklahoma, 2011 (Cause No. PUD 2011-106)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application seeking rider recovery of third party SPP transmission costs and fees.

104. **Oklahoma Gas and Electric Company, 2011 (Cause No. PUD 2011-087) –** Participated as an expert witness on behalf of OIEC before the OCC in OG&E's rate case to provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.

105. **Oklahoma Gas & Electric Company, 2011 (Docket No. 10-109-U)** – Participated as an expert witness on behalf of Gerdau Macsteel before the Arkansas Public Service Commission in OG&E's application to recover Smart Grid costs to make recommendations regarding the allocation of the Smart Grid costs.

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106. **Oklahoma Gas & Electric Company, 2011 (Cause No. PUD 2011-027)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking to include retiree medical expense in the Company's pension tracker mechanism.

107. **Public Service Company of Oklahoma, 2011 (Cause No. PUD 2010-50)** – Participated as an expert witness on behalf of OIEC before the Oklahoma Corporation Commission in AEP/PSO's application to recover ice storm O&M expenses through a regulatory asset/rider mechanism to address tax impact and return issues in the proposed rider.

108. **Public Service Company of Colorado, 2011 (Docket No. 10AL-908E) –** Participated as an expert witness on behalf of the Colorado Retail Council ("CRC") before the Colorado Public Utilities Commission providing written and live testimony to address PSCo's proposed Environmental Tariff.

109. **Oklahoma Gas & Electric Company, 2011 (Docket No. 10-067-U)** – Participated as an expert witness on behalf of the Northwest Arkansas Industrial Energy Consumers ("NWIEC")[9] before the Arkansas Public Service Commission in OG&E's general rate case application to provide testimony on various revenue requirement, cost of service and rate design issues.

110. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-146)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking rider recovery of third party SPP transmission costs and SPP administration fees.

111. **Massachusetts Electric Co. & Nantucket Electric Co. d/b/a National Grid, 2010 (Docket No. DPU 10-54)** – Participated as an expert witness providing both written and live testimony before the Massachusetts Department of Public Utilities on behalf of the Associated Industries of Massachusetts ("AIM") to address the Company's proposed participation in the 438MW Cape Wind project in Nantucket Sound.

112. **Public Service Company of Oklahoma, 2010 (Cause No. PUD 2010-50)** – Participated as an expert witness on behalf of the OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various cost-of-service issues and on the utility's overall revenue requirement and rate design proposals.

113. **Texas-New Mexico Power Co., 2010 (Docket 38480)** – Participated as an expert witness on behalf of the Alliance of Texas Municipalities ("ATM") before the Texas PUC in TMNP's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

114. **Southwestern Public Service Co., 2010 (PUCT Docket No. 38147) –** Participated as an expert witness on behalf of the Alliance of Xcel Municipalities ("AXM") in the SPS general rate case application to provide testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsor the AXM Accounting Exhibits.

115. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-37)** – Participated as an expert witness on behalf of OIEC before the OCC to address the preapproval and ratemaking treatment of OG&E's 220MW self-build wind project.

116. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-29)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking pre-approval of

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[9] NWIEC is an association of industrial manufacturing facilities in northwest Arkansas.

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deployment of smart-grid technology and rider-recovery of the associated costs. Sponsored written testimony to address smart-grid deployment and time-differentiated fuel rates.

117. **Public Service Company of Oklahoma, 2010 (Cause No. PUD 2010-01) –** Participated as an expert witness on behalf of the OIEC before the OCC in the Company's proposed Green Energy Choice Tariff. Sponsored testimony to address the pricing and ratemaking treatment of the Company's proposed wind subscription tariff.

118. **Nevada Power Company, 2010 (Docket No. 10-02009) –** Participated as an expert witness on behalf of the Southern Nevada Hotel Group ("SNHG") before the Nevada PUC to provide testimony in NPC's Internal Resource Plan to address the ratemaking treatment of the proposed ON Line transmission line.

119. **Entergy Texas Inc., 2010 (PUC Docket No. 37744) –** Participated as an expert witness on behalf of the Cities in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

120. **El Paso Electric Company, 2010 (PUC Docket No. 37690)** – Participated as an expert witness on behalf of the City of El Paso in the EPI general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

121. **Public Service Company of Oklahoma, 2009 (Cause No. 09-196) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application for approval of DSM programs and cost recovery. Sponsored testimony to address program costs, lost revenue recovery, cost allocations and incentives.

122. **Oklahoma Gas and Electric Company, 2009 (Cause No. PUD 09-230 and 09-231) –** Participated as an expert witness on behalf of OIEC before the OCC in OG&E's application to add wind resources from two purchased power contracts. Sponsored written testimony to address the proper ratemaking treatment of the contract costs and the renewable energy certificates.

123. **Oklahoma Gas and Electric Company, 2009 (Cause No. PUD 08-398) –** Participated as an expert witness on behalf of OIEC before the OCC in OG&E's rate case. Provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.

124. **Nevada Power Company, 2009, (Docket No. 08-12002) -** Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

125. **Public Service Company of Oklahoma, 2009 (Cause No. 09-031) –** Participated as an expert witness on behalf of OIEC before the OCC in PSO's application to add wind resources from two purchased power contracts. Sponsored written testimony to address the proper ratemaking treatment of the contract costs and the renewable energy certificates.

126. **Oklahoma Natural Gas Co., 2009 (Cause No. PUD 08-348) –** Participated as an expert witness on witness on behalf of the OIEC before the OCC in ONG's application to establish a Performance Based Rate tariff. Sponsored both written and oral testimony to address the merits of the utility's proposed PBR.

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127. **Rocky Mountain Power, 2009 (Docket No. 08-035-38) –** Participated as an expert witness on behalf of the Division of Public Utilities (Staff) in PacifiCorp's general rate case to provide testimony on various revenue requirement issues.

128. **Texas-New Mexico Power Co., 2008 (Docket 36025) –** Participated as an expert witness on behalf of the Alliance of Texas Municipalities ("ATM") before the Texas PUC in TMNP's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

129. **Public Service Company of Oklahoma, 2008 (Cause No. 08-144) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's general rate case application to address revenue requirement and rate design issues to establish prospective cost-of-service based rates.

130. **Public Service Company of Oklahoma, 2008 (Cause No. 08-150) –** Participated as an expert witness on behalf of the OIEC before the OCC to address PSO's calculation of its Fuel Clause Adjustment for 2008.

131. **Oklahoma Gas and Electric Company, 2008 (Cause No. PUD 08-059) –** Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking authorization of its Demand Side Management ("DSM") programs and the establishment of a DSM Rider to recover program costs, lost revenues and utility incentives.

132. **Entergy Gulf States, 2008 (PUC Docket No. 34800, SOAH Docket No. 473-08-0334) –** Participated as an expert witness on behalf of the Cities in EGSI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

133. **Public Service Company of Oklahoma, 2008 (Cause No. 07-465) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application to recover the pre-construction costs of the cancelled Red Rock coal generation facility.

134. **Oklahoma Gas and Electric Company, 2008 (Cause No. 07-447) –** Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking authorization to recover the pre-construction costs of the cancelled Red Rock coal generation facility using proceeds from sales of excess SO_2 allowances.

135. **Rocky Mountain Power, 2008 (Docket No. 07-035-93) –** Participated as an expert witness on behalf of Division of Public Utilities (Staff) in PacifiCorp's general rate case to provide testimony on various revenue requirement issues.

136. **Public Service Company of Oklahoma, 2008 (Cause No. PUD 07-449) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application seeking authorization of its Demand Side Management ("DSM") programs and the establishment of a DSM Rider to recover program costs, lost revenues and utility incentives.

137. **Public Service Company of Oklahoma, 2008 (Cause No. PUD 07-397) –** Participated as an expert witness on behalf of OIEC before the OCC in PSO's application seeking authorization to defer storm damage costs in a regulatory asset account and to recover the costs using the proceeds from sales of excess SO_2 allowances.

138. **Oklahoma Gas & Electric Co., 2007 (Cause No. PUD 07-012) –** Participated as an expert witness on behalf of OIEC before the OCC in OG&E's application seeking pre-approval to construct the Red

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Rock coal plant to address the Company's proposed rider recovery mechanism.

139. **Oklahoma Natural Gas Co., 2007 (Cause No. PUD 07-335) –** Participated as an expert witness on behalf of the OIEC before the OCC in ONG's application proposing alternative cost recovery for the Company's ongoing capital expenditures through the proposed Capital Investment Mechanism Rider ("CIM Rider"). Sponsored testimony to address ONG's proposal.

140. **Public Service Company of Oklahoma, 2007 (Cause No. PUD 06-030) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application seeking a used and useful determination for its planned addition of the Red Rock coal plant to address the Company's use of debt equivalency in the competitive bidding process for new resources.

141. **Public Service Company of Oklahoma, 2006 (Cause No. PUD 06-285) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

142. **Nevada Power Company, 2007, (Docket No. 07-01022)** - Participated as an expert witness on behalf of the MGM MIRAGE before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.

143. **Nevada Power Company, 2006, (Docket No. 06-11022)** - Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

144. **Southwestern Public Service Co., 2006 (PUCT Docket No. 37766) –** Participated as an expert witness on behalf of the Alliance of Xcel Municipalities ("AXM") in the SPS general rate case application. Provided testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsored the Accounting Exhibits on behalf of AXM.

145. **Atmos Energy Corp., Mid-Tex Division, 2006 (Texas GUD 9676) –** Participated as an expert witness in the Atmos Mid-Tex general rate case application on behalf of the Atmos Texas Municipalities ("ATM"). Provided written and oral testimony before the Railroad Commission of Texas regarding the revenue requirements of Mid-Tex including various rate base, operating expense, depreciation and tax issues. Sponsored the Accounting Exhibits for ATM.

146. **Nevada Power Company, 2006 (Docket No. 06-06007) –** Participated as an expert witness on behalf of the MGM MIRAGE in the Sinatra Substation Electric Line Extension and Service Contract case. Provided both written and oral testimony before the Nevada Public Utility Commission to provide the Commission with information as to why the application is consistent with the line extension requirements of Rule 9 and why the cost recovery proposals set forth in the application provide a least cost approach to adding necessary new capacity in the Las Vegas strip area.

147. **Public Service Co. of Oklahoma, 2006 (Cause No. PUD 05-00516) -** Participated as an expert witness on behalf of the OIEC to review PSO's application for a "used and useful" determination of its proposed peaking facility.

148. **Oklahoma Gas and Electric Co., 2006 (Cause No. PUD 06-00041) –** Participated as an expert witness on behalf of the OIEC in OG&E's application to propose an incentive sharing mechanism for SO_2 allowance proceeds.

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149. **Chermac Energy Corporation, 2006 (Cause No. PUD 05-00059 and 05-00177) –** Participated as an expert witness on behalf of the OIEC in Chermac's PURPA application. Sponsored written responsive and rebuttal testimony to address various rate design issues arising under the application.

150. **Oklahoma Gas and Electric Co., 2006 (Cause No. PUD 05-00140) –** Participated as an expert witness on behalf of the OIEC in OG&E's 2003 an 2004 Fuel Clause reviews. Sponsored written testimony to address the purchasing practices of the Company, it transactions with affiliates, and the prices paid for natural gas, coal and purchased power.

151. **Nevada Power Company, 2006, (Docket No. 06-01016) -** Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written testimony in NPC's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.

152. **Oklahoma Gas and Electric Co., 2005 (Cause No. PUD 05-151) –** Participated as an expert witness on behalf of the OIEC in OG&E's general rate case application. Sponsored both written and oral testimony before the OCC to address various revenue requirement and rate design issues for the purpose of setting prospective cost-of-service based rates.

153. **Oklahoma Natural Gas Co., 2005 (Cause No. PUD 04-610) –** Participated as an expert witness on behalf of the Attorney General of Oklahoma. Sponsored written and oral testimony to address numerous rate base, operating expense and depreciation issues for the purpose of setting prospective cost-of-service based rates.

154. **CenterPoint Energy Arkla, 2004 (Cause No. PUD 04-0187) –** Participated as an expert witness on behalf of the Attorney General of Oklahoma: Sponsored written testimony to provide the OCC with analysis from an accounting and ratemaking perspective of the Co.'s proposed change in depreciation rates from an Average Life Group to an Equal Life Group methodology. Addressed the Co.'s proposed increase in depreciation rates associated with increased negative salvage value calculations.

155. **Public Service Co. of Oklahoma, 2004 (Cause No. PUD 02-0754) –** Participated as an expert witness on behalf of the OIEC. Sponsored written testimony (1) making adjustments to PSO's requested recovery of an ICR programming error, (2) correcting errors in the allocation of trading margins on off-system sales of electricity from AEP East to West and among the AEP West utilities and (3) recommending an annual rather than a quarterly change in the FAC rates.

156. **PowerSmith Cogeneration Project, 2004 (Cause No. PUD 03-0564) -** Participated as an expert witness on behalf of the OIEC to provide the OCC with direction in setting an avoided cost for the PowerSmith Cogeneration project under PURPA requirements. Provided both written and oral testimony on the provisions of the proposed contract under PURPA:

157. **Electric Utility Rules for Affiliate Transactions, 2004 (Cause No. RM 03-0003) –** Participated as a consultant on behalf of the OIEC to draft comments to assist the OCC in developing rules for affiliate transactions. Assisted in drafting the proposed rules. Successful in having the Lower of Cost or Market rule adopted for affiliate transactions in Oklahoma.

158. **Nevada Power Company, 2003, (Docket No. 03-10001) -** Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

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159. **Nevada Power Company, 2003, (Docket No. 03-11019)** - Participated as an expert witness on behalf of the MGM MIRAGE before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.

160. **Public Service Company of Oklahoma, 2003 (Cause No. PUD 03-0076) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

161. **Oklahoma Gas & Electric Co., 2003 (Cause No. PUD 03-0226) –** Participated as an expert witness on behalf of the OIEC. Provided both written and oral testimony before the OCC to determine the appropriate level to include in rates for natural gas transportation and storage services acquired from an affiliated company.

162. **Nevada Power Company, 2003 (Docket No. 02-5003-5007)** - Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC. Sponsored written and oral testimony to calculate the appropriate exit fee in MGM Mirage's 661 Application to leave the system.

163. **McCarthy Family Farms, 2003** – Participated as a consultant to assist McCarthy Family Farms in converting a biomass and biosolids composting process into a renewable energy power producing business in California.

164. **Bice v. Petro Hunt, 2003 (ND, Supreme Court No. 20030306)** - Participated as an expert witness in a class certification proceeding to provide cost-of-service calculations for royalty valuation deductions for natural gas gathering, dehydration, compression, treatment and processing fees in North Dakota.

165. **Nevada Power Company, 2003 (Docket No. 03-11019) -** Participated as a consulting expert on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power. Provided written and oral testimony on the reasonableness of the cost allocations to the utility's various customer classes.

166. **Wind River Reservation, 2003 (Fed. Claims Ct. No. 458-79L, 459-79L)** – Participated as a consulting expert on behalf of the Shoshone and Arapaho Tribes to provide cost-of-service calculations for royalty valuation deductions for gathering, dehydration, treatment and compression of natural gas and the reasonableness of deductions for gas transportation.

167. **Oklahoma Gas & Electric Co., 2002 (Cause No. PUD 01-0455) –** Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored written and oral testimony on numerous revenue requirement issues including rate base, operating expense and rate design issues to establish prospective cost-of-service based rates.

168. **Nevada Power Company, 2002 (Docket No. 02-11021) -** Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power and to make recommendations with respect to rate design.

169. **Nevada Power Company, 2002 (Docket No. 01-11029) -** Participated as a consulting expert on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company's deferred energy

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docket to determine the level of prudent company expenditures for fuel and purchased power included in the Company's $928 million deferred energy balances.

170. **Nevada Power Company, 2002 (Docket No. 01-10001) -** Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

171. **Chesapeake v. Kinder Morgan, 2001 (CIV-00-397L) -** Participated as an expert witness on behalf of Chesapeake Energy in a gas gathering dispute. Sponsored testimony to calculate and support a reasonable rate on the gas gathering system. Performed necessary calculations to determine appropriate levels of operating expense, depreciation and cost of capital to include in a reasonable gathering charge and developed an appropriate rate design to recover these costs.

172. **Southern Union Gas Company, 2001** - Participated as a consultant to the City of El Paso in its review of SUG's gas purchasing practices, gas storage position, and potential use of financial hedging instruments and ratemaking incentives to devise strategies to help shelter customers from the risk of high commodity price spikes during the winter months.

173. **Nevada Power Company, 2001 -** Participated as an expert witness on behalf of the MGM-Mirage, Park Place and Mandalay Bay Group before the Nevada Public Utility Commission to review NPC's Comprehensive Energy Plan (CEP) for the State of Nevada and make recommendations regarding the appropriate level of additional costs to include in rates for the Company's prospective power costs associated with natural gas and gas transportation, coal and coal transportation and purchased power.

174. **Bridenstine v. Kaiser-Francis Oil Co. et al., 2001 (CJ-95-54)** - Participated as an expert witness on behalf of royalty owner plaintiffs in a valuation dispute regarding gathering, dehydration, metering, compression, and marketing costs. Provided cost-of-service calculations to determine the reasonableness of the gathering rate charged to the royalty interest. Also provided calculations as to the average price available in the field based upon a study of royalty payments received on other wells in the area.

175. **Klatt v. Hunt et al., 2000 (ND)** - Participated as an expert witness and filed report in United States District Court for the District of North Dakota in a natural gas gathering contract dispute to calculate charges and allocations for processing, sour gas compression, treatment, overhead, depreciation expense, use of residue gas, purchase price allocations, and risk capital.

176. **Oklahoma Gas and Electric Co., 2000 (Cause No. PUD 00-0020)** - Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored testimony on OG&E's proposed Generation Efficiency Performance Rider (GEPR). Provided a list of criteria with which to measure a utility's proposal for alternative ratemaking. Recommended modifications to the Company's proposed GEPR to bring it within the boundaries of an acceptable alternative ratemaking formula.

177. **Oklahoma Gas and Electric Co., 1999 -** Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored testimony on OG&E's proposed Performance Based Ratemaking (PBR) proposal including analysis of the Company's regulated return on equity, fluctuations in the capital investment and operating expense accounts of the Company and the impact that various rate base, operating expense and cost of capital adjustments would have on the Company's proposal.

178. **Nevada Power Company, 1999 (Docket No. 99-7035) -** Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and

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oral testimony addressing the appropriate ratemaking treatment of the Company's deferred energy balances, prospective power costs for natural gas, coal and purchased power and deferred capacity payments for purchased power.

179. **Nevada Power Company, 1999 (Docket No. 99-4005) -** Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony to unbundle the utility services of the NPC and to establish the appropriate cost-of-service allocations and rate design for the utility in Nevada's new competitive electric utility industry.

180. **Nevada Power Company, 1999 (Docket No. 99-4005) -** Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony to establish the cost-of-service revenue requirement of the Company.

181. **Nevada Power/Sierra Pacific Merger, 1998 (Docket No. 98-7023) -** Participated as an expert witness on behalf of the Mirage and MGM Grand before the Nevada PUC. Sponsored written and oral testimony to establish (1) appropriate conditions on the merger (2) the proper sequence of regulatory events to unbundle utility services and deregulate the electric utility industry in Nevada (3) the proper accounting treatment of the acquisition premium and the gain on divestiture of generation assets. The recommendations regarding conditions on the merger, the sequence of regulatory events to unbundle and deregulate, and the accounting treatment of the acquisition premium were specifically adopted in the Commission's final order.

182. **Oklahoma Natural Gas Company, 1998 (Cause No. PUD 98-0177) -** Participated as an expert witness in ONG's unbundling proceedings before the OCC. Sponsored written and oral testimony on behalf of Transok, LLC to establish the cost of ONG's unbundled upstream gas services. Substantially all of the cost-of-service recommendations to unbundle ONG's gas services were adopted in the Commission's interim order.

183. **Public Service Company of Oklahoma, 1997 (Cause No. PUD 96-0214) -** Audited both rate base investment and operating revenue and expense to determine the Company's revenue requirement and cost-of-service. Sponsored written testimony before the OCC on behalf of the OIEC.

184. **Oklahoma Natural Gas /Western Resources Merger, 1997 (Cause No. PUD 97-0106) -** Sponsored testimony on behalf of the OIEC regarding the appropriate accounting treatment of acquisition premiums resulting from the purchase of regulated assets.

185. **Oklahoma Gas and Electric Co., 1996 (Cause No. PUD 96-0116) -** Audited both rate base investment and operating income. Sponsored testimony on behalf of the OIEC for the purpose of determining the Company's revenue requirement and cost-of-service allocations.

186. **Oklahoma Corporation Commission, 1996 -** Provided technical assistance to Commissioner Anthony's office in analyzing gas contracts and related legal proceedings involving ONG and certain of its gas supply contracts. Assignment included comparison of pricing terms of subject gas contracts to portfolio of gas contracts and other data obtained through annual fuel audits analyzing ONG's gas purchasing practices.

187. **Tenkiller Water Company, 1996 -** Provided technical assistance to the Attorney General of Oklahoma in his review of the Company's regulated cost-of-service for the purpose of setting prospective utility rates.

188. **Arkansas Oklahoma Gas Company, 1995 (Cause No. PUD 95-0134) -** Sponsored written and oral

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testimony before the OCC on behalf of the Attorney General of Oklahoma regarding the price of natural gas on AOG's system and the impact of AOG's proposed cost of gas allocations and gas transportation rates and tariffs on AOG's various customer classes.

189. **Enogex, Inc., 1995 (FERC 95-10-000) -** Analyzed Enogex's application before the FERC to increase gas transportation rates for the Oklahoma Independent Petroleum Association and made recommendations regarding revenue requirement, cost-of-service and rate design on behalf of independent producers and shippers.

190. **Oklahoma Natural Gas Company, 1995 (Cause No. PUD 94-0477) -** Analyzed a portfolio of ONG's gas purchase contracts in the Company's Payment-In-Kind (PIC) gas purchase program and made recommendations to the OCC Staff on behalf of Terra Nitrogen, Inc. regarding the inappropriate profits made by ONG on the sale of the gas commodity through the PIC program pricing formula. Also analyzed the price of gas on ONG's system, ONG's cost-of-service based rates, and certain class cross-subsidizations in ONG's existing rate design.

191. **Arkansas Louisiana Gas Company, 1994 (Cause No. PUD 94-0354) -** Planned and supervised the rate case audit for the OCC Staff and reviewed the workpapers and testimony of the other auditors on the case. Sponsored cost-of-service testimony on cash working capital and developed policy recommendations on post test year adjustments.

192. **Empire District Electric Company, 1994 (Cause No. PUD 94-0343) -** Planned and supervised the rate case audit for the OCC Staff and reviewed the workpapers and testimony of other auditors. Sponsored cost-of-service testimony on rate base investment areas including cash working capital.

193. **Oklahoma Natural Gas Company, 1992 through 1993 (Cause No. PUD 92-1190) -** Planned and supervised the rate case audit of ONG for the OCC Staff. Reviewed all workpapers and testimony of the other auditors on the case. Sponsored written and oral testimony on numerous cost-of-service adjustments. Analyzed ONG's gas supply contracts under the Company's PIC program.

194. **Oklahoma Gas and Electric Company, 1991 through 1992 (Cause No. PUD 91-1055)** - Audited the rate base, operating revenue and operating expense accounts of OG&E on behalf of the OCC Staff. Sponsored written and oral testimony on numerous revenue requirement adjustments to establish the appropriate level of costs to include for the purpose of setting prospective rates.

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Exhibit No._____ (MG-2)

Dominion Energy South Carolina, Inc.
DOD/FEA - Summary of Adjustments
Twelve Months Ended December 31, 2019, Docket No. RC 2020-125-E
(Thousands)

Line No.	Description		Reference	Rate Base	Pre-Tax ROR	Rate Increase
1	Requested Amounts		9	$5,748,651		$ 178,234
2	Rate Base Adjustments					
3	Storm Reserve Rider		Exhibit MG-2.6	$ 6,155	10.33619%	$ 636
4	Cash Working Capital		Exhibit MG-2.1	$ (111,424)	10.33619%	(11,517)
5	Construction Work in Progress		Exhibit MG-2.3	(332,821)	10.33619%	(34,401)
6	Total Rate Base Adjustments			$ (438,090)		$ (45,282)
7	Cost of Capital Adjustments					
8	Capital Structure	52.56%	Exhibit MG-2.10	$5,310,561	-0.06%	$ (3,037)
9	ROE	9.10%	Exhibit MG-2.10	$5,310,561	-0.81%	(42,985)
10	Total Cost of Capital Adjustments					$ (46,022)
11	Operating Income Adjustments					
12	Short-Term Incentives		Exhibit MG-2.4			(5,651)
13	Short-Term Incentives Taxes		Exhibit MG-2.4			(490)
14	Long-Term Incentives		Exhibit MG-2.5			(916)
15	Vegetation Management		Exhibit MG-2.6			(3,519)
16	Storm Reserve Rider		Exhibit MG-2.7			(9,840)
17	Turbine Overhaul		Exhibit MG-2.8			(5,009)
18	Unrecovered Plant Amortization		Exhibit MG-2.9			(10,512)
19	Critical Infrastructure Protection Costs		Exhibit MG-2.11			(2,380)
20	Unprotected Plant Related EDIT Amortization		Exhibit MG-2.2			(21,684)
21	Total Operating Income Adjustments					$ (60,002)
22	Total Adjustments					$ (151,306)
23	Recommended Rate Increase					$ 26,928

Dominion Energy South Carolina, Inc.
DOD/FEA - Cash Working Capital
Twelve Months Ended December 31, 2019, Docket No. RC 2020-125-E
(Thousands)

Line No.	Description	Reference	Total Retail
1	Operating Income		
2	Working Cash - Amount Requested	Exhibit C-6, page 2 of 2, line 1, column 5.	$ 111,424
3	Adjustment to Remove Unsupported Cash Working Capital		$ (111,424)

Exhibit MG-2.2

Dominion Energy South Carolina, Inc.
DOD/FEA - Cash Working Capital
Twelve Months Ended December 31, 2019, Docket No. RC 2020-125-E

Line No.	Description		Reference	Total Retail
1	Recommended Unprotected Plant Related EDIT Amortization			$ (25,064,676)
2	Current Unprotected Plant Related EDIT Amortization			(2,677,686)
3	Adjustment to the Amortization of Unprotected Plant EDIT			$ (22,386,990)
4	Jurisdictional Factor		From URR 7-4	96.86%
5	Retail Adjustment to the Amortization of Unprotected Plant EDIT			$ (21,684,038)
6	TCJA Unprotected Plant Related EDIT 12/31/2017	22.314050%	From URR 7-4	$135,000,000
7	TCJA Protected Plant Related EDIT 12/31/2017	77.685950%	From URR 7-4	$470,000,000
8	Total TCJA Plant Related EDIT 12/31/2017			$605,000,000
9	2018 Amortization	($15,365,600)	From URR 7-4	$589,634,400
10	2019 Amortization	(13,000,000)	From ORS 10-12	$576,634,400
11	2020 Amortization	(12,000,000)	From ORS 10-12	$564,634,400
12	2021 Amortization Through March 31	(3,000,000)	From ORS 10-12	$561,634,400
13	Unprotected Portion			22.314050%
14	Unprotected Balance			$125,323,379
15	Amortization Period			5
16	Recommended Annual Amortization			($25,064,676)
17	Current Unprotected Amortization			(2,677,686)
18	Adjustment to the Amortization of Unprotected Plant EDIT			($22,386,990)

Exhibit MG-2.3

Dominion Energy South Carolina, Inc.
DOD/FEA - Construction Work In Progress
Twelve Months Ended December 31, 2019, Docket No. RC 2020-125-E
(Thousands)

Line No.	Description	Reference	Retail Post Test Year Adjustments	Total Retail
1	Operating Income			
2	Construction Work in Progress - Amount Requested	Exhibit C-4, line 13, column 5 and Supplemental Exhibit C-2, page 1 of 3, line 17, column 4.		$ 551,793
3	Updated Additions to CWIP	Response to ORS 8-6, Supp 8-6 Pro Formas Rev W Updates.xlsx, tab 40 Projections, cell K28.	$ 62,567	
4	Projected Additons to CWIP in Application Exhibits	Exhibit No. KCC-2 Supplemental Exhibit C-2, page 3 of 3, Adjustment # 40.	281,539	
5	CWIP Update Adjustment			(218,972)
6	Updated CWIP Balance at September 30, 2020			332,821
7	Adjustment to Remove Plant Not in Service at September 30, 2020			$ (332,821)
8	Total Adjustment to CWIP Included in Application Exhibits			$ (551,793)

Exhibit MG-2.4

Dominion Energy South Carolina, Inc.
DOD/FEA - Short-Term Incentive Plan
Twelve Months Ended December 31, 2019, Docket No. RC 2020-125-E

Line No.	Description	DESC Annual Incentives	DESS Annual Incentives	Totals
1	O&M Expenses			
2	12 Months Ended 12/31/19[1]	$ 8,038,135	$ 4,785,548	$ 12,823,683
3	Less DESC Over Target Adjustment[2]	828,861	424,750	1,253,611
4	Net Incentive Costs Requested	$ 7,209,274	$ 4,360,798	$ 11,570,072
5	Exclude 50% for EPS Funding Mechanism[3] (100% Financial) an	(3,604,637)	(2,180,399)	(5,785,036)
6	Other Financial Goals (30.73% and 34.04% respectively)[4]			
7	O&M Composite Retail Factor[7]	97.6868%	97.6868%	97.6868%
8	South Carolina Retail Adjustment	(3,521,254)	(2,129,962)	**(5,651,215)**
10	Payroll Taxes			
11	12 Months Ended 12/31/19[5]	$ 748,991	$ 362,861	$ 1,111,852
12	Less DESC Over Target Adjustment[6]	72,979	35,704	108,683
13	Net Short-Term Incentive Payroll Taxes	$ 676,012	$ 327,157	$ 1,003,169
14	Exclude 50% for Earnings Based Funding[3]	(338,006)	(163,579)	(501,585)
21	O&M Composite Retail Factor[7]	97.6868%	97.6868%	97.6868%
22	South Carolina Retail Adjustment	(330,187)	(159,795)	**$ (489,982)**

References:

Note 1: From DOD/FEA-DESC 3-13, Exhibit 1 - DESC and DESS short-term incentive award costs 2019, cells D30 and E30

Note 2: From DOD/FEA-DESC 3-13, Exhibit 1 - DESC and DESS short-term incentive award costs 2019, cells D41 and E41

Note 3: See Elbert, 11:13-12:4.

Note 4: From DOD/FEA-DESC 3-13, Exhibit 1 - DESC and DESS short-term incentive award costs 2019, sum of cells D32 and D33 divided by cell D31, and summ of cells E32 and E33 divided by E30.

Note 5: From Exhibit 1 - DESC and DESS short-term incentive award costs 2019, cells H30 and I30

Note 6: From Exhibit 1 - DESC and DESS short-term incentive award costs 2019, cells H41 and I41

Note 7: From Supplemental Exhibit C-2, page 1 of 3, line 4, column 4 amount / Exhibit C-2, page 1 of 4, line 4, column 4 amount.

Exhibit MG-2.5

Dominion Energy South Carolina, Inc.
DOD/FEA - Officer Long-Term Incentive Plan
Twelve Months Ended December 31, 2019, Docket No. RC 2020-125-E

Line No.	Description	Long-Term Incentive	Payroll Taxes	Total
1	Officer Long-Term Accrual[1]	$ 870,490	$ 67,029	$ 937,519
2	Adjustment	$ (870,490)	$ (67,029)	$ (937,519)
3	O&M Composite Retail Factor[2]	97.6868%	97.6868%	97.6868%
4	South Carolina Retail Adjustment	$ (850,354)	$ (65,478)	$ (915,832)

References

Note 1: From Exhibit 1, DESC and DESS short-term incentive award costs 2019, cellsE49 and I49.

Note 2: From Supplemental Exhibit C-2, page 1 of 3, line 4, column 4 amount / Exhibit C-2, page 1 of 4, line 4, column 4 amount.

Exhibit MG-2.6

Dominion Energy South Carolina, Inc.
DOD/FEA - Right of Way Maintenance and Vegetation Management
Twelve Months Ended December 31, 2019, Docket No. RC 2020-125-E

Line No.	Description	Retail Amount
1	DESC Vegetation Management Update Adjustment No. 21	$ 3,786,426
2	DESC Vegetation Management Application Adjustment No. 21	3,519,375
3	Adjustment to Update the DESC Vegetation Management Expenses	$ 267,051
4	Adjustment to Reduce Vegetation Management Expenses to Test Year Levels	$ (3,786,426)
5	Net Vegetation Management Adjustments	$ (3,519,375)

References:
Note 1: From Supp 8-6 Pro Formas Rev w Updates.xlsx, tab 21 Veg Mang, cell J13.

Note 2: From Supplemental Exhibit C-2, page 2 of 3, Adjustment No. 21

Exhibit MG-2.7

Dominion Energy South Carolina, Inc.
DOD/FEA - Storm Damage Reserve
Twelve Months Ended December 31, 2019, Docket No. RC 2020-125-E
(Thousands)

Line No.	Description	Reference	Total Retail
1	Operating Income		
2	Adjustment to Remove Storm Damage Reserve Accrual	From Supplemental Exhibit C-2, page 2 of 3,	$ (9,840)
3	Rate Base		
4	Adjustment to Remove Storm Reserve Liability	From Supplemental Exhibit C-2, page 2 of 3,	$ 7,385
5	Adjustment to Remove Working Capital	From Supplemental Exhibit C-2, page 2 of 3,	$ (1,230)
6	Net Rate Base Adjustment		$ 6,155

Dominion Energy South Carolina, Inc.
DOD/FEA - Production Maintenance
Twelve Months Ended December 31, 2019, Docket No. RC 2020-125-E

Line No.	Description	Description		Total Retail
1	Columbia Energy Center Projected Overhaul Costs 2021 - 2028	From: Attachment 1-5 PF Adj #22 Major Maint Accrual.xlsx, tab 2020 Accrual – Combined, sum of cells D12 - K12	$	36,852,000
2	Additional Annual Accrual Needed for CEC Overhaul Cost		$	4,606,500
3	Reg Asset major Maint Accrual, Account 1823026, 12/31/2019	From: Attachment 1-2 Balance Sheet and Income Statement Details.xlsx, tab Balance Sheet Comparison, cell H401.	$	8,008,543
4	Annual Amortization		$	1,001,068
5	Recommended Increase in Maintenance and Amortization		$	5,607,568
6	DESC Requested Increase in the Overhaul Accrual			10,616,708
7	Adjustment for Turbine Overhaul Accrual and Amortization		$	(5,009,140)

Dominion Energy South Carolina, Inc.
DOD/FEA - Unrecovered Plant (Canady Amortization)
Twelve Months Ended December 31, 2019, Docket No. RC 2020-125-E

Line No.	Description	Reference	Amount
1	Unrecoved Plant Balance 12/31/19	ORS 7-07 1822108 - 12-31-2019 Canady Amort1 xlsx, tab FH 182 2108 Summary, cell AB504	$ 72,551,743
2	Current Annual Amortization	ORS7-07 1822108 - 12-31-2019 Canady Amort1 xlsx, tab FH 182 2108 Summary, cell AA501 * 12	12,270,264
3	Reduction in Recoverable Balance through March 2021	ORS 7-07: 1822108 - 12-31-2019 Canady Amort1 xlsx, tab FH 182 2108 Summary, cell AA501	(15,337,830)
4	Balance for Amortization		$ 57,213,913
5	Recommended Amortization Period, Years		40
6	Recommended Annual Amortization		$ 1,430,348
7	Adjustment to Amortization of Unrecovered Plant		$ (10,839,916)
8	Composite Retail Factor		0.9697733
9	Retail Adjustment ot Unrecovered Plant Amortization		$ (10,512,261)

Dominion Energy South Carolina, Inc.
DOD/FEA - Cost of Capital
Twelve Months Ended December 31, 2019, Docket No. RC 2020-125-E

Line No.	Description	Reference	Amount	Ratio	Rate	ROR Component	Composite Tax Factor	Tax Effected ROR
1	Requested Amounts							
2	Long-Term Debt	From C-7	$3,355,787,000	46.65%	6.46%	3.01%	1	3.01%
3	Preferred Stock		100,000	0.00%	0%	0.00%		0.00%
4	Common Equity		3,837,419,946	53.35%	10.25%	5.47%	1.33913626	7.32%
			$7,193,306,946	100.00%		8.48%		10.34%
5	Recommended Capital Structure							
6	Long-Term Debt			47.44%	6.46%	3.06%	1	3.06%
7	Preferred Stock			0.00%	0%	0.00%		0.00%
8	Common Equity			52.56%	10.25%	5.39%	1.33913626	7.21%
				100.00%		8.45%		10.28%
9	Pre-Tax ROR Adjustment					-0.03%		-0.06%
10	Recommended ROE							
11	Long-Term Debt			47.44%	6.46%	3.06%	1	3.06%
12	Preferred Stock			0.00%	0%	0.00%		0.00%
13	Common Equity			52.56%	9.10%	4.78%	1.33913626	6.41%
				100.00%		7.85%		9.47%
14	Pre-Tax ROR Adjustment					-0.60%		-0.81%

Exhibit MG-2.11

Dominion Energy South Carolina, Inc.
DOD/FEA - Critical Infrastructure Protection Cost Deferral
Twelve Months Ended December 31, 2019, Docket No. RC 2020-125-E
(Thousands)

Line No.	Description	Reference	Total Company	Total Retail
	Recommended Amounts			
1	O&M Expense		$ 2,187	$ 2,117
2	Depreciation and Amortization		272	263
3	Total Recommended Critical Infrastructure Annual Recovery		$ 2,458	$ 2,380
	DESC Requested Amounts			
4	O&M Expense	Exhibit C-2, page 4 of 4, Adjustment 30.	$ 4,373	$ 4,234
5	Depreciation and Amortization	Exhibit C-2, page 4 of 4, Adjustment 30.	543	526
6	Total Requested Critical Infrastructure Annual Recovery		$ 4,916	$ 4,760
7	Adjustment to Critical Infrastructure Annual Costs		$ (2,458)	$ (2,380)

Garrett Group Consulting, Inc.
Incentive Compensation Survey of the 24 Western States
2018 Update

Results by State

Alaska 2011: (Regulatory Commission, Tyler Clark, Finance Manager, 907-276-6222) Incentive Compensation is not an issue in rate cases in Alaska. There is no relevant regulation or policy.

Alaska 2015: (Regulatory Commission, Tyler Clark, Chief Utility Financial Analyst, 907-276-6222) Incentive is not a contested issue yet in Alaska. There are no regulations, policies or cases addressing the issue.

Alaska 2018: (Regulatory Commission, Julie Vogler, Chief Utility Financial Analyst, 907-276-6222) The Commission in Alaska reviews requests to include incentive compensation in rates to determine if they are reasonable and if they benefit ratepayers. Short and long-term incentives receive the same treatment. The issue is handled on a case by case basis. In a recent Enstar Natural Gas case, U-16-066, the Commission allowed the Company's short and long-term incentive expense to be included in revenue requirement. The Final Order in U-16-066 (19), page 62, lines 6 through 14, states:

> The record establishes that the overall cost of ENSTAR's incentive compensation is reasonable in a regulatory context. The scope and mechanics of the STIP and LTIP are clearly defined and described. And incentive compensation payments under the STIP and LTIP have been consistent and are expected to recur at levels comparable to the test year. ENSTAR's incentive compensation plans benefit ratepayers by setting and holding employees to goals that directly relate to customer service and cost controls, and by attracting and retaining highly qualified employees to provide safe and reliable service. We find that inclusion of the incentive compensation amounts as an expense in ENSTAR's revenue requirement is reasonable.

The Enstar case is the first adjudicated case since the last survey results were provided in 2015, so there are no other recent orders that set forth a treatment of the issue.

Arizona: (Corporation Commission, Darron Carlson, 602-542-0834) Arizona deals with incentive compensation plans on a case by case basis. They generally do not allow the costs for these programs to be included in rate base. They have at times allowed 50% of the cost of a particularly good plan to be included in rates.

Arizona 2009: (Corporation Commission, Darron Carlson, 602-542-0834) Arizona deals with incentive compensation plans on a case by case basis. It first compares overall compensation to the state norm, then asks if the cost are prudent and reasonable. They lean toward disallowing programs which benefit only the shareholder even if total compensation is comparable to the state norm.

Arizona 2011: (Corporation Commission, Darron Carlson, 602-542-0834) Still examining case by case, the Arizona Staff's position is that if the company fails to demonstrate that an incentive compensation plan is tied to operational performance issues it is considered unnecessary for the provision of service. Staff feels shareholders should pay for plans tied to financial measures such as earning per share. Most cases settle here and there are no orders on point.

Arizona 2015: (Corporation Commission, Darron Carlson, Manager, Financial and Regulatory Analysis Section, Utility Division, 602-542-0834) Incentive programs are still considered case by case. Evaluation centers around the criteria of benefit to customers. This treatment tends to make long-term programs harder to justify, but the same criteria are used to evaluate all plans including those for executives. This treatment is set forth in the most recent Epcor Water rate case (Docket No. WS-01303A-14-0010). The current treatment represents a somewhat more liberalized approach compared to Arizona's former position of excluding all incentive compensation from rates.

Arizona 2017: A review of Commission decisions in cases since the 2001 Decision 64172 is provided in the testimony of staff witness Ralph C. Smith in Docket No. E-0134SA-16-0036 (pp.81-89). This review demonstrates that the Commission recognizes that financial goals primarily benefit the shareholder and operational goal can benefit the customer. The Commission accordingly shares the cost of short-term incentives equally between ratepayers and the shareholders. In Decision No. 71914 (September 30, 2010), in UNS Electric, Inc. rate case, Docket No. E-04204A-09-0206, the Commission stated at page 28:

> We believe that the Staff and RUCO recommendations, to require a 50/50 sharing of incentive compensation costs, provide a reasonable balancing of the interests between ratepayers and shareholders. The equal sharing of such costs recognizes that the program is comprised of elements that relate to the parent company's financial performance and cost containment goals, matters that primarily benefit shareholders, while at the same time recognizing that a portion of the program's incentive compensation is based on meeting customer service goals. This offers the opportunity for the Company's customers to benefit from improved performance in that area.

Arizona Incentive Compensation Treatment by Case

Short-Term Incentives*

Year	Company	Docket/Decision Number	Lit./Stlmt.	Outcome
2001	SWG	G-01551A-00-0309 / 64172 (p. 13)	Litigated	50:50 Sharing
2007	APS	E-013451-05-0816 / 69663 (p. 37)	Litigated	Allowed**
2008	APS	E-01345A-08-0172	Settlement	50:50 Sharing
2011	APS	E-01345A-11-0224	Settlement	50:50 Sharing
2007	UNS	G-04204A-06-0463 / 70011 (p. 27)	Litigated	50:50 Sharing
2008	UNS	E-04204A-06-0783 / 70360 (p. 21)	Litigated	50:50 Sharing
2006	SWG	G-01551A-04-0876 / 68487 (p. 18)	Litigated	50:50 Sharing

2008	SWG	G-01551A-07-0504 / 70665 (p. 16)	Litigated	50:50 Sharing
2010	UNS	G-04204A-08-0571 / 71623 (pp. 30-31)	Litigated	50:50 Sharing
2010	UNS	E-04204A-09-0206 / 71914 (pp. 28-29)	Litigated	50:50 Sharing

* See Staff witness Smith in APS 2016 Rate Case E-0134SA-16-0036 pp. 81-89.
** The Commission accepted Staff's position: "Staff did not oppose inclusion of the TY variable incentive expense in cost of service, noting that although corporate earnings serve as a threshold or precondition to the payout, the TY level of expense is tied primarily to performance measures that directly benefit APS customer." (page 37)

Arizona 2018: (Corporation Commission, Darron Carlson, Public Utilities Analyst Manager, Revenue Requirements and Audits, 602-542-0834) There have been no changes to the treatment of incentives in Arizona. The issue is still dealt with on a case by case basis centered on benefit to the customer. The treatment is the same for short and long-term plans as well as executive incentives. There are no new orders setting forth the treatment.

Arkansas: (PSC, Alice Wright, 501-682-2051) In the current Entergy Arkansas Rate Case Docket No. 06-101-U, staff witness Jeff Hilton recommends excluding 50% of the portion of plans tied to financial performance, which means disallowing half of the executive's plan. See attached direct and surrebuttal testimony.

Arkansas 2009: (PSC, Jeff Hilton, Manager, Audit Section, General Staff, APSC 501-682-2051) The treatment of incentive compensation has changed recently in Arkansas. The traditional treatment had been to allow in rates those plans based on operational goals (which were seen as benefitting ratepayers), and sharing 50:50 between shareholders and ratepayers the costs of programs which included operational and financial goals (and thereby benefitting both ratepayers and shareholders). The current change is that now, executive plans which are based solely on increasing corporate stock value are seen as benefitting only the shareholders and are excluded from rates. A further refinement of Commission policy is to allow, for any given plan, 50% of the *portion* of that plan which has value for both ratepayers and shareholders. This new treatment is documented in the Entergy order 06-101-U, Order 10, and in the settlement adopted in the latest OG&E case 08-103-U. One reason for the change to exclude these executive plans was that while they were being subsidized by ratepayers they were growing astronomically.

Arkansas 2011: (PSC, Jeff Hilton, Manager, Audit Section, General Staff, APSC 501-682-2051) The Arkansas Commission has uniformly maintained its treatment based on the 2006 Entergy case (06-101-U) cited above. Long-term plans, typically based on stock price, are excluded from rates 100%. Short-term incentive plans are evaluated to determine if they are based on financial or operational measures. Operational-based plans are allowed. 50% of plans containing financial measures are disallowed. Any plans based solely on the discretion of the company are seen as having no direct benefit to ratepayers and are disallowed 100%. Settlements in recent cases have upheld this treatment.

Arkansas 2015: (PSC, Jeff Hilton, Director of Revenue Requirements, 501-682-2051) Commission rulings on Incentive Compensation have remained generally consistent, excluding 100% of long-term plans and 50% of the portion of short-term plans that are financially based. This treatment has been qualified in recent cases based on differing plan structures. In the most recent contested Entergy rate case (Docket No. 13-028-U), 50% of all short-term incentive compensation was excluded because the plans included a financially-based multiplier. The criteria of distinguishing between financial and operational measures that results in different treatment for short and long-term plans is used to evaluate all plans including those for executives. Arkansas' treatment of this issue is considered case by case and is based on prior Commission orders, not legislation. While the Commissioners' position has remained consistent, Staff's recommendation in the last several cases, including 13-028-U and two currently under review, has shifted. Staff has recently considered that any incentive compensation plan which they find is prudent and is necessary for the provision of utility service to ratepayers should be included in rates. Based on these criteria, Staff has recommended no disallowance in these three cases, a position which the Commission did not adopt in the 13-028-U Entergy case.

Arkansas 2018: (PSC, Jeff Hilton, Director of Revenue Requirements, 501-682-5185) The Arkansas Commission continues to follow the precedent of its previous orders and generally disallows 50% of financially based Short-term incentive plans and 100% of Long-term plans (which include the executive plans). There is some flexibility for considering a utility's particular situation on a case by case basis, but the two larger utilities in Arkansas, Entergy and CenterPoint, are both on formula rate plans and the 50%/100% disallowance treatment is incorporated in those FRPs, based on their most recent respective rate cases, 15-015-U and 15-098-U, in which the Commission specifically expressed this preference.[1]

California: (PUC, Pamela Thompson, Div. of Ratepayer Advocacy, 415-703-5581, Mark Pocta, 415-703-2871) In CPUC Decision 00-02-046 the Commission established that utilities could recover 50% of the regular employee's incentive compensation costs from rates. Mark Pocta says they advocate for some type of sharing arrangement and points out that PGE has a 50/50 arrangement for both executive and employee plans, while Southern California Edison passes 50% of its executive plan and all of its employee plan to ratepayers.

California 2009: (PUC, Mark Pocta, Division of Ratepayer Advocacy, 415-703-5581) In California, incentive compensation funding is always an issue and is typically litigated. In California's latest litigated rate case, Southern California Edison (Application #: 07-11-011, Decision #: 09-03-025) the DRA argued for disallowing of incentive compensation in rates citing vague performance measure and the fact that all the plans were, at least in part, based on the Company's financial performance. The Commission, however, decided that the non-executive plans (at Edison there are plans for all employees) and 50% of the short-term executive plans will be funded in rates, while only the long-term executive stock option plans will be disallowed. In 2000, in the PGE case (CPUC Decision 00-02-046), the Commission allocated a 50:50 sharing of all the management incentive compensation programs between ratepayers and shareholders.

California 2011: (PUC, Matthew Tisdale (CPUC), Pamela Thompson, Mark Pocta, Division of Ratepayer Advocacy, 415-703-5581) No response from California in 2011.

California 2015: (PUC, Richard Rauschmeier, Financial Examiner, DRA - Division of Water and Audits, 415-703-2732) The Commission considers incentive compensation on a case by case basis. Plans are evaluated in the context of an overall reasonableness standard. The Commission has also established

1 In Docket No. 15-015-U, Order No.18, pp. 18-20, the Commission reversed a settlement treatment which disallowed only 25% of financially-based Short-term incentives, imposing instead a 50% disallowance.

precedence for evaluating plans based on who benefits from the plans' goals, ratepayer or shareholders. This approach quite often results in different outcomes for short-term and long-term plans. In determining overall reasonableness, the Commission also considers many other criteria such as comparisons with similarly sized utilities, benchmarking to related industry, internal historical trends and overall compensation. In a recent case, A.10-07-007, staff recommended that, "customer funding should be limited to the portion of the incentive plan payments that are aligned with operational objective that provide customer benefits. This means that 70% of AIP be funded by shareholders, and 30% be funded by ratepayers." In the settlement, the Commission disallowed 50% of the plan's expense. One change that may impact consideration of incentives going forward is the Commission's renewed focus on safety since the San Bruno pipeline explosion. The Commission is establishing metrics for observing historical trends and industry comparisons, and is emphasizing neutral third-party benchmarking.

California 2018: (CPUC, Richard Rauschmeier, Financial Examiner, Public Advocate's Office, 415-703-2732) The CPUC examines utility company requests to include incentive compensation in rates on a case by case basis, but the criteria are well established. Generally, incentive compensation expense can be charged to ratepayers only to the extent it is aligned with ratepayer interests. Typically, this treatment results in disallowance of the portion of short-term incentives tied to financial performance [2]. The Commission's consistent practice is to reject recovery of long-term incentives, "because, LTI does not align executives' interests with ratepayer interests."[3] Since the 2010 San Bruno pipeline explosion (and other events including the Aliso Canyon Leak, and the Witch, Guejito and Rice Wildfires which were found to be caused by utilities), legislative and regulatory interest in utility safety has intensified[4]. Consequently, the treatment of incentives is increasingly framed by asking whether the incentives are safety-focused or earnings-focused.

Colorado: (PUC, Rob Trokey, 303-894-2121) Colorado has no regulatory or statutory rules governing incentive compensation and considers it on a case by case basis. In the 2006 PSC Colorado (electric utility) Rate Case 06-S-234-EG, the Office of Consumer Council argued for removing the costs of the portion of the plan not benefiting ratepayers. That case settled without the Commission ruling. In the current gas utility rate case staff is removing incentive compensation from rate base.

Colorado 2009: (PUC, Karl Kunzie, Financial Analyst: Economics Section, 303-894-2882, P.B. Scheckter, Office of Consumer Counsel (OCC), 303-894-2124) Colorado has no rules or statues and, due to black-box settlements, no recent orders on point. Historically, the policy of the OCC has been to disallow plans tied to goals such as price per share, and allow in rates those plans tied to quality of service and goals that benefit ratepayers. The PUC has tended not to oppose the company's historic test year payouts. However, in the current Public Service Company of Colorado (Xcel Energy) rate case, Staff has argued to exclude all types of incentive compensation from rates. This treatment holds that incentive compensation, in general, benefits only the shareholder, that it is discretionary and sometimes is not be paid out, and that all of it should be paid for by the shareholders. The goals related to ratepayer benefit

2 Examples of this treatment: Decision 15-11-021, Decision 12-11-051 and Decision14-08-032.
3 Decision 15-11-021 at 262
4 CPUC's view of incentives in terms of promoting a positive or negative safety culture is discussed at length in Decision 16-06-054 (San Diego Gas & Electric). Also see R.15-09-010, D.11-06-017 and Public Utilities Code Section 706.

should be considered part of the job and compensated for by regular wage and salary. In this treatment, if total compensation is then non-competitive the regular, non-optional component of compensation should be raised.

Colorado 2011: (PUC, Karl Kunzie, Financial Analyst: Economics Section, 303-894-2882) Colorado staff has made the decision not to seek to eliminate all incentive compensation (rolling compensation for goals benefitting ratepayers into regular salaries). All executive incentives are still excluded from rates and no longer sought in company filings. Regular employee programs are judged on their benefit to ratepayers verses stockholders. Plans with metrics for goals benefiting ratepayers but dependent on an earnings per share trigger are considered to benefit shareholders and opposed by staff. Staff's approach is set forth most recently, in 10AL-963G by staff witness Kahl. The settlement in that case removed the dollar amount opposed by Kahl without specifically stating the rationale.

Colorado 2015: (PUC, Karl Kunzie, Financial Analyst: Economics Section, 303-894-2882) Colorado still excludes long-term executive incentive compensation from rates. However, with respect to annual incentive pay (AIP), Colorado's treatment has changed significantly. In the most recent rate case for Public Service Company of Colorado, staff recommended the Commission, "limit reimbursement of incentive pay to no more than 15 percent of employee base salary." In this Proceeding No. 14AL-0660E / Order C15-0292, the Settling Parties agreed to reduced the revenue requirement by a dollar amount without agreeing to any specific adjustments. However, on the issue of AIP, the Settlement Agreement included the statement, "the Settling Parties agree AIP incentive payment recovery in the 2017 Rate Case will be capped at 15% of an employee's salary." This treatment does not evaluate incentive compensation plans based on some criteria such as their prudence, or which stakeholder group benefits from the goals of a plan. With respect to choosing a straight percentage of salary, Staff's witness, Fiona Sigalla, noted in her testimony of November 7, 2014: "Annual incentive plan payments to employees exceed 10 percent of salary for most workers and tops 100 percent of salary for some executives." "In 2014, the top 20 highest paid Xcel Energy executives received AIP payments that averaged over 100 percent of salary. Limiting reimbursement of incentive pay to 15 percent of base pay would mostly impact these higher paid employees." "Fifty-six percent of the impact for 2013 affects reimbursement of incentive pay for Company executives." This treatment is expected to continue at least through the term of the 2017 PSCo rate case.

Colorado 2018: (PUC, Karl Kunzie, Financial Analyst: Economics Section, 303-894-2882) There have been no changes to the treatment of incentive compensation in Colorado since the last update to the survey. Long-term incentives are not allowed recovery in rates. Recovery of short-term plans is limited to 15% of base salary without evaluating plan goals. This treatment was followed in the PSCo Gas rate case in 2018, Proceeding No. 17AL-0363G. No change to this treatment is anticipated.

Hawaii 2011: (PUC, Steven J. Iha, Chief Auditor, 808-586-2020) Hawaii does not allow incentive compensation to be included in rates. This policy was set forth in Docket No. 6531, in the October 17, 1991 Order No. 11317. Prior Dockets in which the Commission disallowed incentive compensation include No. 3216, No. 4215, No. 4588 and No. 5114. In 6531 the Commission agreed that bonus awards tied to company income and earnings benefit stockholders, not ratepayers. The Commission further states, "...we believe that a utility employee, especially at the executive level, should perform at an optimum level without additional compensation. Ratepayers should not be burdened with additional costs for expected levels of service." In the 1991 case, the Commission also excluded the negative deferred income taxes associated with incentive plans which were disallowed from the deferred income taxes that are deducted from the rate base.

Hawaii 2015: (PUC, Steven J. Iha, Chief Auditor, 808-586-2020) Hawaii's general policy toward incentive compensation has not changed. Incentive compensation of all types is excluded from rates. The Commission upholds the position stated in Docket No. 6531 that incentives tied to company income and earnings benefit stockholders, not ratepayers. The Commission further stated, "...we believe that a utility employee, especially at the executive level, should perform at an optimum level without additional compensation. Ratepayers should not be burdened with additional costs for expected levels of service." Utilities in Hawaii no longer petition to have incentive compensation expense included in rates.

Hawaii 2018: (PUC, Jan K. Mulvey, Chief Auditor, 808-586-2020) Hawaii's longstanding policy to exclude all incentive compensation expense from rates remains firmly in place. The Commission upholds the position stated in Docket No. 6531 that incentives tied to company income and earnings benefit stockholders, not ratepayers. The Commission stated at page 59, "We recognize that incentives encourage cost reductions in some instances. However, we believe that a utility employee, especially at the executive level, should perform at an optimum level without additional compensation. Ratepayers should not be burdened with additional costs for expected levels of service." This treatment is not challenged by the utilities.

Idaho: (PUC, Terri Carlock, Accounting Section Supervisor, 208-334-0356) As general policy, Idaho does not allow into rates the costs associated with profits and earnings performance, but does allow a portion of plans that benefit the ratepayer through improved customer service, etc. Executive's incentive compensation plans are evaluated using the same criteria and are not often allowed. See Idaho Power Company Rate Case IPC-E-05-28 Corrected Motion for Approval of Stipulation 3/1/06, 6e, p. 4; Idaho Power Company IPC-05-28 Order No. 30035, p. 4/10.

Idaho 2009: (PUC, Terri Carlock, Accounting Section Supervisor, 208-334-0356) The Commission's basic policy for evaluating incentive compensation plans involves determining who benefits, the customer or the company. This treatment has been refined (in the recent Idaho Power Company general rate case) for plans which benefit the customer but require a financial trigger (e.g. must meet a certain dividend level) to be paid. For these plans the Commission reduced the percentage allowed in rates. The Commission also now does not include any executive compensation in rates. The Commission's focus on customer benefit is reflected in the direct testimony of Staff witness, Leckie, and in the final order for the recent IPC General Rate Case IPC-E-08-10. For earlier examples of the basic policy, see Idaho Power Company Rate Case IPC-E-05-28 Corrected Motion for Approval of Stipulation 3/1/06, 6e, p. 4; Idaho Power Company IPC-05-28 Order No. 30035, p. 4/10 (attached '07).

Idaho 2011: (PUC, Terri Carlock, Utility Division Deputy Administrator, Accounting Section Supervisor, 208-334-0356) Treatment of incentive compensation remains unchanged in Idaho. Ms. Carlock summarizes the Idaho Public Utility Commission treatment as follows, "For Idaho utility companies, the short answer is that incentives that are based on targets that provide customer benefits, i.e. customer service, reliability, O&M budgets, safety etc., are included in rates. Incentives that are based on targets that provide shareholder value are excluded." Executive plans typically fall into the second category and are excluded. More specifically: Idaho Power has an Executive Incentive Plan that is separate from the Annual Employee Incentive Plan, and it is excluded from rates. Avista has one plan Incentive Plan that has different targets based on different criteria. Executives participate in this plan, but because executives have a different set of targets, only the targets associated with customer service and reliability are included in rates. Pacificorp Incentive Plan, each individual employee has their own set of goals and targets in order to achieve an incentive payment, and those targets are different for executives. Executive incentives have not requested for rate recovery.

Idaho 2015: (PUC, Terri Carlock, Utility Division Deputy Administrator, Accounting Section Supervisor, 208-334-0356) Idaho's treatment of incentives has not changed - most is disallowed. To be included in rates a plan must benefit ratepayers. Plans based on measures which benefit shareholders, such as increased earnings, are excluded. This treatment is the same for all plans including those for executives. There are no recent orders on point, but the three rate case scheduled this year are expected to reflect this treatment.

Idaho 2018: (PUC, Terri Carlock, Utility Division Administrator, Accounting Section Supervisor, 208-334-0356) There has been no change to the treatment of incentives in Idaho. The Commission allows in rates those incentives that benefit customers and exclude those based on financial measures that benefit shareholders. This treatment is the same for incentives at all levels, but executive plans receive closer scrutiny as it is often harder to find customer benefit in these plans. There are no recent orders on point and no changes are anticipated in the near future.

Iowa: (Utilities Board, Wes Birchman, 515-281-5979) Incentive compensation is not an issue here as they do not do many rate cases.

Iowa 2009: (Utilities Board, Wes Birchman, 515-281-5979, Dan Fritz, 515-281-5451) Mid-America has an incentive compensation plan but hasn't filed a rate case in many years. For the state's other utilities, it has been a long time since they have filed a rate case or had a rate increase. The standing treatment is to look at incentive compensation plans on a case by case basis and evaluate whether or not they are reasonable and prudently incurred.

Iowa 2011: (Utilities Board, Dan Fritz, 515-725-7316) Both of the investor owned utilities in Iowa are under rate freezes until 2013 and 2014. There has been no change in the treatment of utility incentive compensation.

Iowa 2015: (Utilities Board, Dan Fritz, 515-725-7316) Incentive Compensation has not been an issue in Iowa. There are no specific treatments in place and the Commission will review the merits and prudence of a proposed plan on a case by case basis. There are no recent orders on point, and no treatment changes are anticipated.

Iowa 2018: (Utilities Board, Dan Fritz, 515-725-7316) There have been no changes in the treatment of Incentive Compensation. There are no specific treatments in place and the issues is handled on a case by case basis. There are no recent orders on point.

Kansas: (Corporation Commission, Utilities Div., Larry Holloway, Chief of Engineering Operations, 785-271-3222) On a case by case basis staff opposes plans without ratepayer benefit or are lacking objective measures.

Kansas 2009: (Corporation Commission, Utilities Division, Bob Glass, Chief of Economic Section, 785-271-3175) The Commission views incentive compensation plans that are based solely on financial performance as benefitting only the shareholders and not something that belongs in rates. In the last 5 to 10 years the Commission has not seen incentive compensation as a major issue and tends not to challenge plans that are reasonable by industry standards as long as they are based on a multidimensional set of criteria involving both reliability and financial goals. In Kansas, the Commission also funds the Citizens Utility Rate Board (CURB), an advocacy group for the residential and commercial ratepayers. CURB argues that any portion of a plan that relates to financial measures should be disallowed.

Kansas 2011: (Corporation Commission, Utilities Division, Jeff McClanahan, Chief of Accounting and Financial Analysis, 785-271-3212) The Kansas Commission recently has changed its stance on incentive compensation. In the litigated 2010 KCP&L rate case (10-KCPE-415-RTS) the Commission stated that relying on peer group statistics "can result in a continuing upward spiral [instead] the Commission must examine the elements of incentive packages, and the behavior they incent". For executive incentive programs, the Commission disallowed 100% of payments based on purely financial measures and 50% for plans using a balance of financial and operational measures. The Commission allowed in rates the non-executive annual incentive program after Staff found that KCP&L had modified the measures used in this plan and, "eliminated all focus on profitability or earning [which might incent employee behavior] detrimental to customers."

Kansas 2015: (Corporation Commission, Utilities Division, Justin Grady, Chief of Accounting and Financial Analysis, 785-271-3164) The Kansas Corporation Commission continues to rely on the treatment it established in the litigated 2010 KCPL rate case (10KCPE-415-RTS) and followed in the 2012 case, 12-KCPE-764-RTS. For officer level incentives, plans are evaluated to determine whether the objectives of the plan are geared to improve the company's financial results or to improve operational objectives. The financially-based portion is borne by the shareholders and the portion supporting operational goals is allowed in rates. The exception to this evaluation process are any time-based restricted stock plans which vest solely on the passage of time. Such plans are seen as being neutral and therefore split 50:50 between shareholders and ratepayers. Non-officer incentive compensation plans for workers are allowed in rates. This treatment is becoming established as the Commission's general policy[5] and has guided Staff's position on these issues in both of it current rate cases for KCPL (15-KCPE-116-RTS) and Westar (15-WSEE-115-RTS). However, the consumer advocacy branch, Citizens' Utility Ratepayer Board (CURB) has consistently recommended the more aggressive position of applying the same financial/operational criteria to non-officer plans as well. In the current KCPL rate case the company has voluntarily excluded 50% of the restricted stock plans, 100% of the performance-based plans, 50% of the short-term plans which are based on an earnings-per-share qualifier. The Company has also removed the earnings-per-share portion of their Value Rewards Plan which is open to all employees. This was seen as an attempt to find the middle ground between staff's position and that of CURB. In this case CURB did not make an adjustment challenging the company's proposed recovery.

5 In the 2012 KCPL rate case (12-KCPE-764-RTS) this treatment resulted in a 50:50 split of the short-term plan. For the long-term incentives, the Commission excluded 50% of the time-based restricted stock portion of the plan, and 100% of the portion based on stockholder return.

Kansas 2018: (Corporation Commission, Utilities Division, Kristina Luke-Fry, Managing Auditor, 785-271-3171) Kansas still allows all employee-level incentives in rates. For management and executive incentives, the Commission only allows in rates those incentives related to safety and other operational objectives, and excludes incentives related to financial measures such as earnings per share. This treatment is based on prior orders, especially 10KCPE-415-RTS and 12-KCPE-764-RTS. This treatment has the result of excluding the majority of executive incentives due to the fact that they are usually tied to company earnings. There are no recent orders on point, and no changes in treatment are anticipated.

Louisiana 2009: (PSC, Brian McManus, Economist, Division of Economics and Rates Analysis, 225-342-2720; Bill Barta, Henderson Ridge consulting, 770-205-8828) Louisiana has traditionally held that the incentive compensation plan for upper level management and officers are excluded from rates, while those of lower level of managers and employees are included in rates. The criteria originally used to arrive at this treatment considered whether the goals of each plan more directly benefitted ratepayers or shareholders. Recently, an ALJ's report in the Entergy Louisiana Formula Rate Plan 2006 (Docket # U - 20925, 2006 Evaluation Period) has recommended excluding all stock option plans for all levels. The Commission has also recently chastised Entergy for excessive bonuses.

Louisiana 2011: (PSC, Brian McManus, Economist, Division of Economics and Rates Analysis, 225-342-2720) The Louisiana Commission does not allow Executive Bonuses to be recovered from ratepayers. This is especially true for the larger utilities. For incentive awards to employees that are not Executives, the Commission may allow recovery. For some of the smaller utilities the Commission may allow bonuses to management if the whole compensation package is reasonable. There has not been any docketed proceeding since 2006.

Louisiana 2015: (PSC, Brian McManus, Economist, Division of Economics and Rates Analysis, 225-342-2720) No response from Louisiana at this time.

Louisiana 2018: (PSC, Robin Pendergrass, Audit Director, (225-342-1457) The treatment of incentive compensation in Louisiana has not changed. The LPSC does not allow Executive incentive compensation plans to be recovered from ratepayers. Lower level management and employee incentive awards may be included, assuming they are reasonable. To determine reasonableness, the Commission looks at the amount of the incentive in relation to 1) the size of the company 2) the job duties of the employee and 3) the average hours worked during the test year. The Commission also looks at who benefits, ratepayers or shareholders. This is a general auditing policy utilized in all LPSC rate reviews. Recent dockets which followed this treatment, where disallowances were made using these criteria, include Dockets U-34667 and U-34669, which are the 2017 annual RSP filings for CenterPoint Arkla and CenterPoint Entex, respectively. Both dockets show disallowances for competitive and incentive pay and other executive compensation.

Minnesota: (PUC, Louis Sickmann, Financial Analyst, 651-201-2243) Minnesota looks at incentive packages on a case by case basis. Since the 1991 decision to deny incentive compensation costs in the

ESP Electric Rate Case, the Commission has begun to allow inclusion of employee plans. It capped these plans (at 15% of base salary) out of a concern that larger percentages tied the employees too closely to shareholders' interests. Current caps are at 25% of base salaries. The portions of these plans that are allowed into rates are tracked and must be returned to ratepayers if they are not paid to employees (as has been the case when earnings per share targets were not met). Executive plans are largely not allowed. See General Rate Case E002/GR/05/1428, September 1, 2006.

Minnesota 2009: (PUC, Louis Sickmann, Financial Analyst, 651-201-2243) Minnesota's treatment of incentive compensation has changed recently. One influence that has allowed this change is that Minnesota's utilities have move away from asking the Commission to include in rates those plans that are tied strictly to company earnings. Currently plans which are based on earnings and don't include goals that benefit the ratepayer are limited to long-term management plans which are excluded from rates. The two new parts of Minnesota's treatment of plans that do benefit ratepayers are, first, to cap those plans at 25% of base salary and , second, to refund all portions of the plan which are not actually paid out to employees.

Minnesota 2011: (PUC, Jerry Dasinger, Financial Analyst, 651-201-2235) Minnesota continues to distinguish between incentive plans tied to financial triggers (such as a threshold ROE), and plans tied to criteria benefitting the ratepayer. Plans based on goals which benefit ratepayers are allowed in rates, but their costs are still capped at 25% of base salaries. This cap is being challenged by arguments to lower it to 15%. This general policy is demonstrated in recent orders in the Minnesota Power and Ottertail rate cases: E002/GR-09-1151 and E002/GR-10-239 respectively.

Minnesota 2015: (PUC, Sundra Bender, Financial Analyst, 651-201-2247) Minnesota continues to distinguish between incentive plans tied to financial triggers (such as a threshold ROE) and plans tied to criteria benefitting the ratepayer. Plans based on goals which benefit ratepayers are generally allowed in rates, but their costs are frequently capped at a percentage of base salaries such as 15% or 25% (the percentage can vary from case to case). Utilities are usually required to return to ratepayers any portion of incentive pay that was allowed into rates and is not subsequently paid out to employees. Executive and long-term IC measures are frequently more closely aligned with shareholder interests and thus are not usually allowed in rates. An example of the Commission's treatment is set forth in General Rate Case G-008/GR-13-316, June 9, 2014 Findings of Fact, Conclusions, and Order at pages 13-17 and page 58.

Minnesota 2018: (PUC, Sundra Bender, Financial Analyst, 651-201-2247) Minnesota continues to determine allowable incentive compensation on a case by case basis. Annual incentive plan compensation is usually allowed in rates, but the costs are frequently capped at a percentage of base salaries, for example: 15%, 20%, or 25% (the percentage can vary from case to case). Utilities are usually required to return to ratepayers any portion of incentive pay that was allowed into rates and is not subsequently paid out to employees. Long-term incentive compensation measures are not usually allowed in rates. A recent case example is the Minnesota Power General Rate Case E-015/GR-16-664, March 12, 2018 Findings of Fact, Conclusions, and Order at pages 31-34 and 110.

Missouri: (PSC, Utility Services Div., Bob Schallenberg, 573-751-7162) On a case by case basis, Missouri includes plans that benefit consumers and otherwise disallows incentive compensation plans. The same criteria are used for executive plan – few are allowed. See recent Kansas City Power and Light and Empire Electric District orders on the Commission's website.

Missouri 2009: (PSC, Utility Services Div., Bob Schallenberg, Manager, 573-751-7162) In Missouri, value to the customer is the general policy that informs their treatment of incentive compensation plans. A plan's goals must be beneficial to the customer or the plan is not allowed in rates. Plans based on rate of return, for example, are not allowed. This treatment also applies to executive plans which generally have less chance of being allowed in rates. See Ameren ER 2009-0318.

Missouri 2011: (PSC, Utility Services Div., Bob Schallenberg, Manager, 573-751-7162) Missouri's treatment remains consistent in disallowing incentives tied to goals benefitting primarily the stockholders (e.g. tied to earnings per share) while allowing plans with customer-specific goals (e.g. safety). However, even these plans must be reasonable to be allowed. For example, in the last Missouri American rate case (WR-2010-0131), not only were plans based on financial goals disallowed, but incentive payments based on customer satisfaction were disallowed due to the unreasonably small sample size used to establish a positive rating (a phone survey of 927 of roughly 450,000 customers). The Commission also removed incentive payments tied to lobbying and charitable activity. In the most recent case processed, the Ameren UE rate case, the company didn't seek even short-term incentive compensation tied to earnings demonstrating that staff's practice is becoming accepted by the companies. In that case, the Commission did allow some payments related to service, but only the amounts actually paid, not those accrued. All incentive compensation adjustment were made not only to expense charges, but to construction charges as well.

Missouri 2015: (PSC, Utility Services Div., Bob Schallenberg, Manager, 573-751-7162) Incentives are addressed on a case by case basis. Plans are analyzed to determine who benefits. Plans that can show a direct benefit to customers (and that are found to be prudent) are allowed in rates. Plans that benefit shareholders are excluded. This treatment does not typically result in a different outcome (being allowed or disallowed in rates) for short-term verses long-term plans. Executive plans are less often allowed in rates due to ties to rate of return. There are no recent orders which demonstrate this treatment.

Missouri 2018: (PSC, Commission Staff Div., Mark Oligschlaeger, Manager, Auditing Department, 573-751-7443) Missouri's treatment for incentives, generally, is to allow rate recovery for those plans with goals that, if achieved, would lead to improved or more economical service to customers and with the goals known to employees in advance so as to be a real motivational tool. Incentives tied to financial goals such as earnings per share, net income or stock price growth are not allowed. These criteria are used to evaluate all incentive plans, short or long-term, as well as those for executives. This treatment is not proscribed by statute or rule, but has been the longstanding policy of the Commission, and was followed in the recent Spire Missouri rate cases, Case Nos. GR-2017-0215 and GR-2017-0216. There have been no recent changes to this treatment, and none are anticipated in the near future.

Montana: (PSC, Eric Eck, Chief, Revenue Requirement Bureau, 406-444-6183) Montana has no rule or policy concerning incentive compensation and no recent cases on point. They deal with the issue on a case by case basis.

Montana 2009: (PSC, Eric Eck, Chief, Revenue Requirement Bureau, 406-444-6183) Montana has no rules or recent cases dealing with incentive compensation.

Montana 2011: (PSC, Eric Eck, Chief, Revenue Requirement Bureau, 406-444-6183) Montana has no changes in its treatment of incentive compensation. It has no specific treatment directive and considers the issue on a case by case basis. In a recent NorthWestern Energy rate case, as part of a stipulation agreement, the company took a portion of its incentive compensation out of rates, but reserved the right to propose that it be included in a later filing.

Montana 2015: (PSC, Eric Eck, Chief, Revenue Requirement Bureau, 406-444-6183) Due to the low volume of litigated cases in the past 10 to 15 years in Montana, incentive compensation has not been an important issue before the Commission. This Commission is focused more on significant investment in infrastructure, such as the ongoing distribution project by NorthWestern. Incentive compensation is considered the responsibility of the utility's Board of Directors and is generally not challenged. However, the Commission tends to become more concerned by incentive plans that are tilted toward financial performance instead of operational goals. Short and long-term plans are handled similarly, and the Commission prefers plans that are broadly available to employees.

Montana 2018: (PSC, Gary Duncan, Revenue Requirements and Audits, 406-444-6189) Incentive compensation has not been a contested issue in the three rate cases in Montana since the 2015 survey. All utility compensation, including incentives, is recovered through rates in Montana.

Nebraska: (Public Service Commission, Laura Demman, Director and Legal Counsel, Natural Gas Department, NPSC, 402-471-3101) Nebraska is unique in that all of its electric demand is supplied by consumer-owned power districts, cooperatives, and municipalities. The Natural Gas Department of the NPSC regulates the rates and service quality of investor-owned natural gas public utilities pursuant to the state's Natural Gas Regulation Act passed in 2003. Nebraska does not have rules regarding incentive compensation and considers the issue on a case by case basis. In a 2007 rate case, NG-0041, with Aquila (later acquired by Black Hills), the Commission allowed in rates only the actual amounts paid, an adjustment to provide for a known and measurable expense. This order further adjusted the company's application by half, directing that cost should follow benefit and stating, "However, the Commission further finds that the nature of the objectives appear to benefit both ratepayers and shareholders and it would be improper for the ratepayers to bear the full cost of this benefit." In a subsequent Black Hills case, NG-0061, the Commission again ordered a "known and measurable" adjustment. In NG-0060 the Commission disallowed the entire amount requested by SourceGas for cash incentive bonuses citing insufficient information on the record to adequately describe the bonuses.

Nebraska 2015: (Public Service Commission, Angela Melton, Director and Legal Counsel, Natural Gas Department, NPSC, 402-471-3101) There has been no change in the treatment of incentive compensation as a ratemaking issue in Nebraska.

Nebraska 2018: (Public Service Commission, Nichole Mulcahy, Director and Legal Counsel, Natural Gas Department, 402-471-0234) There have been no changes in Nebraska's handling of incentives. The Commission still practices the policy that cost should follow benefit and allows in rates the actual amount paid on incentive plans that benefit ratepayers. This treatment is the same for all incentive plans. There are no recent orders on point and no changes are anticipated.6

Nevada: 100% of long-term incentives are disallowed. Short-term incentives are divided between financial and operational goals with 100% of financially based plans disallowed. In Nevada Power's 2008 rate case, the Commission excluded 100% of the long-term plan for executives and key employees of the company, based on the fact that these costs mainly benefit shareholders. In Nevada Power's 2011 rate case, Docket No. 11-06006, the Company voluntarily excluded the costs of its long-term plan.

Nevada 2015: No change in Nevada's treatment.

Nevada 2018: (Nevada response provided by Mark Garrett) No change in Nevada's treatment.

New Mexico: (Public Regulation Commission, Charles Gunter, Accounting Bureau, 505-827-6940) The technical staff takes the general position that the portion of an incentive program that is based on increasing share value should be paid for by shareholders. Any that benefits ratepayers and makes up part of a reasonable base pay should be part of rates. Plans are evaluated on a case by case basis. Charles Gunter writes, "Staff took the position that 20 percent of Public Service Company of New Mexico's Results Based Pay costs were properly allocable to customers, because 20 percent of the maximum possible RBP award was tied to achieving goals pertaining to customer satisfaction, cost control, safety, reliability and operations efficiency. By comparison, 80 percent of the maximum possible award was tied to achieving corporate financial goals and EPS targets. See pages 11-13 of Andria Delling's (505-827-6962) testimony in 06-00210-UT."

New Mexico 2009: (Public Regulation Commission, Charles Gunter, Accounting Bureau Chief, Economist, 505-827-6975) The Commission does not favor incentive compensation plans that are tied to financial goals and tends to allow in rates those based on operational goals. This standard is applied to plans at all levels of utility employees and tends to knock out a greater proportion of executive plans. See Docket 07-00077-UT

New Mexico 2011: (Public Regulation Commission, Charles Gunter, Accounting Bureau Chief, Economist, 505-827-6977) There has been no change in NMPRC's treatment of incentive compensation except that due to the current economic conditions, Staff is even more opposed to incentive compensation and wage increases.

6 In a 2007 rate case, NG-0041, the Commission disallowed 50%, directing that cost should follow benefit and stating, "However, the Commission further finds that the nature of the objectives appear to benefit both ratepayers and shareholders and it would be improper for the ratepayers to bear the full cost of this benefit."

New Mexico 2015: (Public Regulation Commission, Charles Gunter, Accounting Bureau Chief, Economist, 505-827-6977) Incentive programs tied to measures that benefit ratepayers (such as operation and safety) are allowed in rates. Programs tied to the financial performance of the utility (e.g. stock price or ROE) are not allowed in rates. Executive incentive plans receive more scrutiny as they are more likely to have financial measures. They can also be challenged if the overall percentage is out of line. One major utility in New Mexico no longer includes the compensation of its top 5 executives in rate applications. The treatment of incentive compensation as a ratemaking issue has become generally established by practice and plans are considered on a case by case basis. There are no recent orders setting out this treatment, and no changes are anticipated.

New Mexico 2018: (Public Regulation Commission, Charles Gunter, Accounting Bureau Chief, Economist, 505-827-6977)) There has been no major change in the treatment of incentive compensation since the last update. The Commission considers this issue on a case by case basis and generally allows recovery through rates of those incentives that are reasonable in amount and tied to metrics that have benefit for customers, such as operational excellence and safety. Incentives that are financially based, for example those tied to stock price performance or earnings, are not allowed in rates. This treatment was followed in the Southwest Public Service Company's 2017 rate case, 17-00255-UT. The Commission described this treatment as its longstanding practice in the order in Public Service Company of New Mexico's rate case, 15-00261-UT. Some utilities in New Mexico no longer seek recovery of management incentives in rates.

North Dakota: (PSC, Mike Diller, Director of Accounting, 701-328-4079) In North Dakota, the general policy is the portion that relates to earnings of the shareholders is disallowed and the rest is included.

North Dakota 2009: (PSC, Mike Diller, Director of Accounting, 701-328-4079) Historically, North Dakota has followed the general policy that the portion of incentive compensation that relates to shareholder earnings is disallowed and the rest is included. The issue has recently been reframed. In the last rate case (Xcel/Northern States Power Company) the Commission followed the "Minnesota Solution": they capped incentive compensation for employees at 15% of base pay (company had asked for 25%). Any incentive compensation over the 15% level was not included in rates. Executive incentive compensation was not allowed in rates, and was not sought by the company to be in rates in this case nor in the last Xcel case (see p. 2, of McDaniel, Direct – attached; and p. 46, C of A.E. Heuer).

North Dakota 2011: (PSC, Mike Diller, Director of Accounting, 701-328-4079) The Commission has not accepted the financial verses performance, or shareholder verses ratepayer perspective on incentive compensation as recently argued by witness George Mathai. The Commission chose to look at the overall compensation and judge whether or not it was reasonable compared to the market. Other than Xcel, the utilities in North Dakota (Otter Tail and MDU) are highly diversified now (with mostly unregulated operations, e.g. MDU 90%). This allows utility executives to draw on the unregulated components for their compensation.

North Dakota 2015: (PSC, Mike Diller, Director of Accounting, 701-328-4079) Incentive compensation is dealt with on a case by case basis and there is no standard policy for the issue. The Commission has in the past limited incentives to 15% of salary. The general approach is to determine if incentive compensation is reasonable and fair based on market analysis. There have been no recent orders on point, and no changes in treatment are anticipated.

North Dakota 2018: (PSC, Patrick Fahn, Director of Public Utilities Division, 701-328-4079) Incentives are treated on a case by case basis, but the Commission's general policy is to allow in rates incentive compensation that is tied to customer benefit and to disallow incentives tied to company financials and corporate benefit. This treatment is the same for all types of incentive plans. Executive incentives are always requested by the utilities but are historically not allowed in rates unless shown that the incentive compensation is tied to customer benefits. The current 2017 Otter Tail rate case, PU-17-398, is expected to follow this treatment. No changes to this treatment are anticipated in the near future.

Oklahoma : The Commission excludes incentive payments tied to financial performance. From a practical perspective this means that all executive stock plans are excluded and some portion of the annual cash plan for all employees. Since the Commission has not been able to determine in recent years the precise portion of the annual plans tied to financial measures, the Commission has excluded 50% of the expense. All of the executive stock plan costs are routinely excluded. (See Commission orders in AEP-PSO Cause No. PUD 06-285; OG&E Cause No. PUD 05-151; and ONG Cause No. PUD 04-610).

Oklahoma 2009: The Commission's policy toward incentive compensation is unchanged in 2009. In AEP-PSO's recently decided rate case (final order issued 1-14-09), the Commission exclude all of the long-term incentive compensation plans and 50% of the annual plans. (See Final Order No. 464437 in AEP-PSO Cause No. 08-144).

Oklahoma 2011: The Commission's policy toward incentive compensation is unchanged in 2011.

Oklahoma 2015: No change in Oklahoma's treatment.

Oklahoma 2018: (Oklahoma response provided by Mark Garrett) No change in Oklahoma's treatment.

Oregon: (PUC, Judy Johnson, Mgr. Rates and Tariffs, 503-378-6636) Oregon PUC's general policy is that all officer bonuses are 100% deleted from rates. For employee incentives plans, the part that is based on customer service is allowed and the part that is based on increased return is disallowed, resulting in 50-50 to 70-30 splits between shareholders and ratepayers. Utilities have begun to adopt this structure in their IC plans.

Oregon 2009: (PUC, Judy Johnson, Mgr. Rates and Tariffs, 503-378-6636) No substantial change in treatment. The Commission's general policy is to evaluate plans based on whether they benefit the customers or the company. Customer-based plans (involving reliability, response speed, etc) are called "merit" plans. Company-based plans (which track increases to the bottom line, ROE, etc) are called "performance" plans. 50% of the cost of merit plans is disallowed from rates and 75% of performance plans are disallowed from rates. 100% of officer bonuses are disallowed. A recent order reflecting this policy is found in Docket UE 197, Order No. 09-020 (attached).

Oregon 2011: (PUC, Judy Johnson, Mgr. Rates and Tariffs, 503-378-6636) No change in treatment. Still categorize "merit" or "performance" plans and disallow from rates 50% and 75% respectively. 100% of officer bonuses are disallowed.

Oregon 2015: (PUC, Judy Johnson, Mgr. Rates and Tariffs, 503-378-6636) The Commission's general policy is based on the idea that customers should not have to pay for incentive compensation based on financial goals such as rate of return. This treatment typically results in 50% to 75% of short-term incentives being allowed in rates. However, in the case of a plan with 3 of its 4 goals based on financial measures, 75% of the cost of that plan would be excluded from rates. The only long-term plans are for officers, and 100% of officer incentives are excluded from rates. This treatment is not expected to change.

Oregon 2018: (PUC, John Crider, Administrator - Energy Rates, Finance and Audits Division, 503-373-1536) The treatment of incentives in Oregon has not changed. Short-term, non-officer incentive plans are seen as having benefit to ratepayers; 50% of merit-based plans are disallowed from rates and 75% of plans related to company performance are disallowed[7]. Long-term officer and executive plans are seen as benefitting shareholders and are 100% disallowed[8]. This is a long-standing policy based on previous orders.

South Dakota: (PUC, Dave Jacobson, Analyst, 605-773-3201) The criteria used here is incentives that are triggered by shareholder returns are disallowed.

South Dakota 2009: (PUC, Dave Jacobson, Analyst, 605-773-3201) The Commission's general policy is to disallow the portion of incentive plans that are based strictly on returns. Current treatment also includes disallowing both executive and non-executive management incentive compensation. Also, there are no incentive compensation plans for union employees. Rate cases settle here so there are no orders on point.

South Dakota 2011: (PUC, Dave Jacobson, Analyst, 605-773-3201) South Dakota PUC is opposed to including in rates incentive compensation plans based on the company's financial performance. In Docket No. EL 08-030 the settlement excluded bonuses related to "stockholder-benefitting financial goals." The settlement in Xcel rate case Docket No. EL09-009 removed payments based on financial performance indicators. In the settlement agreement signed July 7, 2010 in the Black Hills Power rate case Docket No. EL09-018 the Staff Memorandum states, "The settlement removes financial based incentive payments that were included in the capitalized labor costs for plant. Shareholders are the overwhelming beneficiaries of incentive plans that promote the financial performance of the Company and therefore should be responsible for the cost of such compensation." Jacobson noted that several utilities have whole incentive programs that hinge on whether or not the company earns a certain return. These financial prerequisites cause the whole plans to be excluded from rates. The same treatment is used for management and employee plans.

7 See Orders: 76-601 p.13, 77-125 p. 10, 87-406 pp. 42-43
8 See Orders: 99-033 p. 62 and 97-171 pp.74-76

South Dakota 2015: (PUC, Eric Paulson, Utility Analyst, 605-773-6347) South Dakota considers incentive compensation on a case by case basis. Their general policy is to evaluate each plan and disallow the portion based on financial performance indicators. This treatment is set forth in the recent case EL14-026 in which the order specifically excluded the amount "tied to the Company's financial results." This policy is not anticipated to change.

South Dakota 2018: (PUC, Eric Paulson, Utility Analyst, 605-773-6347) There has been no change in South Dakota's treatment of incentives since 2015. Incentives with stockholder-benefiting financial goals are excluded from rates. This treatment is the same for incentive plans at all levels. Recent orders (issued 6/15/16) which follow this treatment are found in dockets EL 15-024 and NG 15-005. This treatment is not expected to change.

Texas: The Public Utility Commission regulates the electric utilities in Texas. The PUC's general rule is that incentive payments designed to increase the financial position of the utility are excluded. For example, in PUC Docket No. 28840, the Commission disallowed sixty-six percent (66%) of AEP-Texas Central's test year incentive payments in the amount of $4.2 million. This was the portion of the utility's incentive payments that was based on financial performance measures. (See Application of AEP Texas Central Company for Authority to Change Rates, Docket No. 28840; SOAH Docket No. 473-04-1033, Final Order, August 15, 2005; ALJ's Proposal for Decision at page 113 in PUC Docket No. 28840, SOAH Docket No. 473-04-1033, issued July 1, 2004. The PFD with respect to the treatment of incentive compensation was adopted by the Commission in its Final Order.)

Gas utilities are regulated by the Railroad Commission. The treatment of the RRC is consistent; financial incentives are out of rates and customer-related incentives are allowed in. Examples of this treatment can be found in Atmos 9670 Order and Order on Rehearing, Texas Gas Service Company 9988 Final Order, Centerpoint 9902 Final Order and Centerpoint 10106 Final Order. In Docket 9670 both the executive and employee plans for Atmos Mid-Tex were found not to be just and reasonable because they, "advanced the interest of shareholders, and [are] driven by Company earnings." None of the costs of these programs were allowed in rates. In Docket 9988 the RRC found 100% of long-term and 90% of short-term incentives expense was "unreasonable" because it was related to the financial performance of ONEOK Inc. 10% of the short-term plan was allowed in rates because it was based on safety metrics.

Texas 2015: (PUC, Larry Reed, Senior Fuel Analyst, 512-936-7357) No response from Texas PUC at this time. A recent example of the Texas commission's well established policy of excluding financially based incentives is set forth in 2011 rate case of Entergy Texas Inc. (PUC Docket No. 39896). In PUC Docket No. 40295, Entergy's application for rate case expense in the 39896 case, the Commission also disallowed the amount of rate-case expenses related to financially-based incentive compensation. The 40295 Order reads at page 2:

> The Commission affirms the proposal for decision regarding the need to reduce Entergy's recoverable expenses due to an unreasonable position pursued by Entergy in the rate case and also affirms the use of the "issue-specific reduction approach" to determine how to calculate an appropriate reduction in rate-case expenses when the utility takes positions that are in conflict with Commission precedent.
>
> Specifically, the Commission agrees with the ALJ that reductions should be made to Entergy's recoverable rate-case expenses for Entergy

> attempting to recover financially-based incentive compensation in base rates. The Commission has repeatedly ruled that a utility cannot recover the cost of financially-based incentive compensation because financial measures are of more immediate benefit to shareholders and financial measures are not necessary or reasonable to provide utility services.[9] The Commission concludes that it should follow its well-established policy here.
>
> However, the ALJ did not include all of the impacts attendant to the disallowance for incentive compensation.[10] To calculate the amount of the reduction in rate-case expenses related to financially-based incentive compensation, the Commission starts with Entergy's initial rate-case expense request, reduced by $208,494 in disallowances made by the ALJ and affirmed by the Commission. The Commission further reduces this amount by an additional $522,244.66, which is the amount of rate-case expenses related to financially-based incentive compensation using the issue-specific reduction approach.

Texas 2015: (Railroad Commission, Mark Evarts, Director, Market Oversight and Safety Services Division, 512-427-9057) No response from Texas RRC at this time.

Texas 2018: (PUC, Anna Givens, Director, Financial Review, 512-936-7462) The longstanding policy of the Commission is to exclude from rates all financially-based incentives. Incentives based on operational goals may be included in rates. Long-term incentives are typically financially based and are excluded. Executive incentives receive the same treatment. This treatment is not proscribed by statute or rule, but has been the consistent policy of the Commission since 2005 when it issued the Final Order in Docket No. 28840. Recent orders in litigated cases that set forth this treatment include SWEPCO rate cases Docket Nos. 40443 and 46449, and the SPS rate case Docket No. 43695. One recent refinement to the treatment of this issue in Texas is that for plans that are otherwise based on acceptable operational metrics but are paid only if a financial goal is met, only 50% of the portion that is subject to the financially-based proviso is allowed in rates. This split occurs before consideration of the individual components of the compensation plan goals and 100% of incentive plan goals tied directly to financial goals are further excluded. In the SWEPCO proceeding, Docket No. 46449, the Company's EPS funding goal was weighted 75%, so the disallowance was 50% of the 75% weighting and resulted in an adjustment that was less than 50% of the total plan that was otherwise based upon acceptable operational metrics. This refinement reflects that a plan has a financially-based funding trigger and requires employees to meet metrics that include financial goals, in addition to performance-

[9] *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 28840, Proposal for Decision at 92-97, Findings of Fact Nos. 164-170, Order at 35 (Aug. 15, 2005); *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 33309, Proposal for Decision at 116-121, Finding of Fact No. 82, Order on Rehearing at 12 (March 4, 2008); *Application of Oncor Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 35717, Proposal for Decision at 96-100, Finding of Fact No. 93, Order on Rehearing at 22 (Nov. 30, 2009); and *Application of CenterPoint Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 38339, Proposal for Decision at 66-67, Findings of Fact Nos. 81-83, Order on Rehearing at 22 (June 23, 2011).

[10] Docket No. 39896, Order on Rehearing at 5-6, 7-8 (Nov. 2, 2012).

related goals. There are no imminent changes in the PUC's treatment, however there are some efforts to have it codified as a Commission Rule.

Texas 2018: (Railroad Commission, Mark Brock, Utility Analyst, 512-463-7018) The Commission handles incentive compensation on a case by case basis.

(Texas Railroad Commission Update) A statute (H.B. 1767) passed in 2019 for gas utilities, but not electric utilities, establishes a rebuttable presumption that short-term incentives for utility employees are reasonable and necessary if the utility can show they are market-based. The statute does not include financial-based incentives for named executives. Also, it is not clear if the statute covers incentives allocated from corporate or from a service company.

Utah: (PSC, Jim Logan, Commission Utility Economist (PSC), 801-530-6716) The general policy in Utah is the portion of the plan based on rate payer benefit, such as service quality, is allowed and the portion that relates to earning and rate of return are disallowed. See US West Communications Rate Case Docket 95-049-05; Missouri Corp. Rate Case Docket 97-035-01 Order signed 3/4/99, pp. 10-12.

Utah 2009: (PSC, Jim Logan PhD, Commission Utility Economist (PSC), 801-530-6707) The Commission's general policy (backed by orders) is to allow in rates the parts of a plan that are tied to ratepayer benefit and disallow the parts tied to financial goals. Executive incentive compensation is excluded from rates. The recent final order in 07-035-93 follows this general policy. See also US West Communications Rate Case Docket 95-049-05; Missouri Corp. Rate Case Docket 97-035-01 Order signed 3/4/99, pp. 10-12.

Utah 2011: (PSC, Carol Revelt, Energy and Electric Economist, 801-530-6711) There have been no changes in Utah's treatment of incentive compensation. The Commission's general policy is to allow in rates the parts of a plan that are tied to ratepayer benefit and disallow the parts tied to financial goals.

Utah 2015: (PSC, Carol Revelt, Energy and Electric Economist, 801-530-6711) The Commission's general policy is to allow in rates the parts of a plan that are tied to ratepayer benefit and disallow the parts tied to financial goals. This policy was followed in the PacifiCorp General Rate Case Docket No. 07-035-93, pp. 61-62; the US West Communications Rate Case Docket 95-049-05; and Missouri Corp. Rate Case Docket 97-035-01, pp. 10-12. There are no recent orders on point and no changes in policy are anticipated.

Utah 2018: (PSC, Carol Revelt, Energy and Electric Economist, 801-530-6711) The Commission considers incentive compensation on a case by case basis and whether the incentive compensation program is reasonable. Historically the general policy has been to allow in rates the parts of a plan that are tied to ratepayer benefit and disallow the parts tied to financial goals. There have been no recent commission decisions addressing this issue.

Washington: (WUTC, Roland Martin, staff, 360-664-1304) Treated on a case by case basis. Typically allow the component tied to efficiency increases and disallow the part that results from increasing the bottom line. See Docket 061546, Pacific Power and Light, Order

Washington 2009: (WUTC, Roland Martin, staff, 360-664-1304) No change in treatment. Evaluated on a case by case basis, this treatment allows the parts of plans tied to measures such as reliability and customer satisfaction and disallows the parts tied to financial measures and the bottom line.

Washington 2011: (WUTC, Roland Martin, Regulatory Analyst, 360-664-1304) No change in treatment. Still addressed on case by case basis, allowing in rates those incentives that are tied to operational efficiency or other measures which benefit ratepayers, and disallowing incentives based on return on earnings or other measures that benefit the shareholders. Recommended website: www.utc.wa.gov.

Washington 2015: (WUTC, Roland Martin, Regulatory Analyst, 360-664-1304) No change in treatment. Still addressed on case by case basis, allowing in rates those incentives that are tied to operational efficiency or other measures which benefit ratepayers, and disallowing incentives based on return on earnings or other measures that benefit the shareholders.

Washington 2018: (WUTC, Amy Andrews, Senior Policy Advisor, 360-664-1304) Washington's treatment of incentive compensation is largely based on previous cases, but remains a case-by-case basis. Generally, Short-term incentives are allowed in rates with Long-term incentives being excluded. There are no recent orders that set forth this treatment.

Wyoming: (PSC, Marci Norby, Senior Rate Analyst, 307-777-5720) Wyoming considers incentive compensation on a case by case basis. The general approach is to determine if the program is reasonable.

Wyoming 2009: (PSC, Marci Norby, Senior Rate Analyst, 307-777-5720) Executive incentive compensation plans are all excluded from rates. Employee incentive compensation plan are evaluated on a case be case basis. Criteria for evaluation include that optional portions of the plans are based on performance goals not financial measures, and the total compensation is compared to a market standard. Currently most employee plans meet these criteria and are allowed in rates.

Wyoming 2011: (PSC, Marci Norby, Senior Rate Analyst, 307-777-5720) Policy here remains the same, distinguishing between employee programs that benefit the ratepayer or the stockholders and requiring the benefitting party to pay. Executive plans are excluded.

Wyoming 2015: (PSC, Marci Norby, Senior Rate Analyst, 307-777-5720) Incentive compensation has not been an issue in some time here. There are no governing regulations, statutes or general policies and the issue would be decided on a case by case basis after considering the history and goals of a program in the context of a rate case. There are no recent orders on point, and no changes in treatment are anticipated.

Wyoming 2018: (PSC, Marci Norby, Senior Rate Analyst, 307-777-5720) There has been no change in the way that incentives are treated in Wyoming. Incentives are generally evaluated on a case by case basis to determine if they are just and reasonable, giving attention to plan goals and historical context. There are no governing regulations, statutes or general policies in place, and there are no recent orders on point. No changes in treatment are anticipated.

Exhibit MG-4

Data Request Responses Cited
Direct Testimony of Mark E. Garrett
Docket No. 2020-125-E

Testimony	Cited Data Request Responses
DOD-FEA 3-51	p.48, fn. 66
ORS 4-7(b), cell K229	p. 62, fn. 87
DOD-FEA 1-38	p. 78, l. 22
DOD-FEA 1-39	p. 82, l. 3
DOD-FEA 1-34	p. 86, l. 3

<u>List of Responses:</u>

DOD-FEA 3-51
ORS 4-7(b), Excerpt with Cell K229 Circled
DOD-FEA 1-38
DOD-FEA 1-39
DOD-FEA 1-34

REQUEST NO. 3-51:

Please provide the amounts expensed for vegetation management for each year 2015 through 2019.

RESPONSE NO. 3-51:

Vegetation management expenses totaled $106,007,900.04 between 2015 and 2019. Expenses by year are below:

Year	O&M - Tree Trimming	O&M - Herbicide	Total O&M Expense
2015	$23,449,254.51	$100,198.13	$23,549,452.64
2016	$19,242,385.67	$103,670.38	$19,346,056.05
2017	$19,091,016.51	$99,500.43	$19,190,516.94
2018	$18,894,081.31	$96,606.57	$18,990,687.88
2019	$24,824,574.87	$106,611.66	$24,931,186.53
Grand Total	$105,501,312.87	$506,587.17	$106,007,900.04

Dominion Energy South Carolina, Inc.
Docket No. 2020-125-E
Response to ORS Request 4-7(b)

PSC Major Maintenance Accrual

Project Listing - By year when taken against the Accrual

Plant	Event	Description	Grand Total	2011	2012	2013	2014	2015	2016	2017	2018	2019
	Grand Total		230,460,707.79	11,500,545.27	11,071,357.28	18,103,562.57	19,356,008.73	16,527,014.55	23,805,202.94	26,127,334.37	16,340,764.02	10,457,522.52
			Annual Accrual	$ (18,435,780.00)	$ (18,435,780.00)	$ (18,435,780.00)	$ (18,435,780.00)	$ (18,435,780.00)	$ (18,435,780.00)	$ (18,435,780.00)	$ (18,435,780.00)	$(18,435,780.00)
			MMA Over/Under Activity	(6,935,234.73)	(7,364,422.72)	(332,217.43)	920,228.73	(1,908,765.45)	5,369,422.94	7,691,554.37	(2,095,015.98)	(7,978,257.48)
			Carrying Costs	238,986.37	93,433.54	51,167.53	120,857.75	34,887.13	151,747.46	272,149.20	610,007.59	336,656.79
			Cumualtive Balance with Carry Costs	14,030,023.19	6,759,034.01	6,477,984.11	7,519,070.59	5,645,192.27	11,166,362.67	19,130,066.24	17,645,057.85	10,003,457.16
			Balance per G/L	14,029,573.00	6,758,584.00	6,477,534.00	7,518,621.00	5,644,743.00	11,165,913.00	19,129,617.00	17,644,610.00	10,003,011.00
			Difference	450.19	450.01	450.11	449.59	449.27	449.67	449.24	447.85	446.16

REQUEST NO. 1-38:

Please explain the basis of the power factor correction in Rate 24. Specifically address why a threshold of 85% is utilized.

RESPONSE NO. 1-38:

The Company has used an 85% power factor for decades to promote efficient use of power, minimize transformer and line losses, and reduce costs for other customers. Other large electric utilities in the state of South Carolina, including Duke Energy Carolinas, Duke Energy Progress, and the South Carolina Public Service Authority also utilize an 85% threshold for power factor.

REQUEST NO. 1-39:

What would be the impact of using a threshold of 90% power factor on the proposed Rate 24?

RESPONSE NO. 1-39:

While the Company has not conducted a formal analysis of the impact of raising its power factor correction threshold to 90%, such a request would likely impose greater costs on its customers, either through required technology/process/equipment improvements (such as capacitors) required at customer facilities, or through increased billing charges for certain customers whose current facilities receive electric service from DESC and whose usage falls between 85% and 90% power factor.

REQUEST NO. 1-34:

Please explain why Rate 23 is available only to customers with major industrial group of manufacturing with 10-14 or 20-39 as the first two digits of the Standard Industrial Classification or 21 or 31-33 as the first two digits of the six digit North American Industry Classification System using the Company's standard service for power and light requirements.

RESPONSE NO. 1-34:

Order No. 1993-465 in Public Service Commission of South Carolina Docket No. 1992-619-E approved changes to the Company's Rate 23 limiting its availability to accounts classified as industrial by Standard Industrial Classification ("SIC") codes.

The Company's reasoning provided in direct testimony during that general rate proceeding was that "Industrial customers devote large amounts of their electric usage to production which is not weather sensitive. Accordingly, they have a much better load factor -- that is, their year round use is much higher compared to their contribution to summer peak. Non-industrial load is generally more weather sensitive. Non-industrial customers show much higher increases in demand during summer peaks when the weather is hot. Accordingly, they have much more ability to control peak contribution by load shifting. Moving these customers off Rate 23 to Time-Of-Use rates will assist in conservation efforts. Non-industrial accounts are proposed to be moved to Rate 24 - Large General Service Time-of-Use. However, these customers will be able to choose from any of the other rates available to them. This change will provide economic incentives for these non-industrial customers to engage in load management techniques that will be cost beneficial and increase energy efficiency."

Garrett Group, LLC
Cash Working Capital Survey of Western States
2011 Survey with Updates

Results by State

Alaska: (Regulatory Commission, Tyler Clark, Finance Manager, 907-276-6222)

Arizona: (Corporation Commission, Darren Carlson, 602-542-0834) Arizona excludes depreciation, deferred taxes and net income in lead/lag studies but will consider including interest expense on long-term debt on a case by case basis. Arizona has no rule or statue defining the elements of a lead/lag study. Cash working capital is generally a negative number for most utilities for which it is considered in rate cases. When interest on long-term debt is considered the Commission staff looks primarily at the type and volume of the debt. The ACC addressed these specific issues in Decision No. 69663 in a recent APS rate case, Docket No. E-01345A-05-0816. In that case, APS included depreciation expense in its lead-lag study and excluded interest expense on long-term debt. Both Staff and RUCO recommended the opposite treatment for both items. The Arizona Commission reviewed testimony and legal briefs on both issues and provided a thorough analysis in its final order to support its decision that the cash working capital allowance should include interest but not depreciation expense in the analysis.

(12/8/14) In Arizona, larger utilities requesting cash working capital in rates supply lead-lag studies. This is a well established policy based on previous Commission orders. Smaller utilities may use the "Formula Method" which is calculated using ⅛ of operating expense and 1/24 of purchased power expense and is always positive. Smaller utilities (class D and E Gas, Electric, Water and Sewage utilities) are those with annual revenues less than $250,000. Utility classifications are scheduled to change in 2015. Under the new class sizes, Mr. Carlson expects utilities with annual revenues in excess of $1,000,000 to be expected to file lead-lag studies when seeking cash working capital in rates. Arizona does not have a rule requiring a particular method to support requests for cash working capital in rates. The 45 Day Formula or ⅛ Rule, to the extent it is distinguished from the "Formula Method" described above, is not used and is not asked for in Arizona.

(6/6/16) (Corporation Commission, Darren Carlson, 602-542-0834) Arizona still uses the same treatment, requiring larger utilities to file a lead-lag study when requesting cash working capital, and including interest on long-term debt in lead-lag studies. Recent rate cases have settled, but the treatment is consistent.

Arkansas: Arkansas uses a Modified Balance Sheet Approach.

(2/25/15) Lead-Lag studies are the only other method of support allowed by the Minimum Filing Requirements B.4, *Calculations of Working Capital Assets,* besides the Modified Balance Sheet Approach (MBSA) the Commission routinely uses to calculate cash working capital. The 45 Day Formula or ⅛ Rule is not allowed though it might be considered as support for a specific adjustment if shown to be reasonable. No utilities in Arkansas use or request to use the 45 Day Formula or ⅛ Rule to support requests for cash working capital in rate base.

California: (PUC, Julie Fitch, Energy Div. Dir. 415-703-2059, Paul Phillips Retail Rate Design, 415-703-3134, Matthew Tisdale (CPUC), Pamela Thompson, Mark Pocta, Division of Ratepayer Advocacy, 415-703-5581) No response was received from California to the CWC inquiry. However, Mr. Garrett believes that California may include non-cash items in lead-lag analysis.

(2/19/15) (PUC, Richard Rauschmeier, Financial Examiner, Division of Water and Audits, 415-703-2731) Major utilities are required to use the Detailed Basis which uses Lead-Lag studies. In California, small utilities determine a working cash allowance using the Simplified Basis. In this method, the utility's average monthly operating expenses are multiplied by a certain number of months (0.5 - 2.5 months based on billing schedules) less one month's average purchased power expense. This allowance is then reduced by the amount of tax accruals. An example of a small utility is a water company with less than 10,000 connections. These policies are specified in Standard Practice *U-16-W*. Major utilities do not use or ask for the 45 Day Formula or ⅛ Rule and typically rely on updating older Lead-Lag studies.

Colorado: (PUC, Karl Kunzie, Financial Analyst: Economics Section, 303-894-2882) Net income, depreciation and deferred income tax expenses are not included in lead/lag studies in Colorado. Interest expense on long-term debt is sometimes included. There is no rule, order or statute established and in the past Public Utility has not included interest expense but the OCC has argued for its inclusion. Black Hills didn't include interest, but recently settled with the OCC and now includes interest expense in its lead/lag study. A recent case that shows none of these items in a lead/lad study is 10AL-963G and the most-recent Black Hills Electric case, which includes interest, is 11AL-387E.

(2/24/15) Colorado does not have a rule requiring Lead-Lag studies, but staff asks for one if it is not provided with requests for cash working capital. In Mr. Kunzie's experience, the Commission has never provided cash working capital without a Lead-Lag study. The Commission has not allowed a utility to rely on the 45 Day Formula or ⅛ Rule in recent memory and no utility has ask to be allowed to use the 45 Day Formula or ⅛ Rule.

Hawaii: (PUC, Steven J. Iha, Chief Auditor, 808-586-2020) The commission uses lead lag studies with the larger utilities in Hawaii. The components have been establish by practice since the late 1980's and are no longer contested. Depreciation expense, deferred income tax expense, net income and interest on long-term debt are not included in lead lag studies. This treatment is set forth in the most recent Hawaiian Electric Company rate case, 2010-0080 in Exhibit B of the order issued 7/22/2011.

(2/24/15) Use of Lead-Lag studies to support requests for cash working capital in rates is a long-established practice in Hawaii. No requests for the 45 Day Formula or ⅛ Rule have been made by a major utility and to do so they would have to justify its use over a Lead-Lag study. A formula method has been adopted for small water and sewer companies.

Idaho: Idaho: (PUC, Terri Carlock, Utility Division Deputy Administrator, Accounting Section Supervisor, 208-334-0356) Idaho utilizes the "balance sheet" approach for large utilities even if a lead/lag analysis is filed for computing cash working capital. If a lead/lag study is done, non-cash items are not included in the calculation. This would include depreciation expense, deferred income tax expense and net income.

(3/10/15) Idaho utilities requesting cash working capital in rate base have filed a Lead-Lag study in addition to their balance sheet approach. This additional support for working capital lag times helps the Commission look at who actually pays for each component. Small utilities, like small water companies are allowed to use a percentage calculation like the 45 Day Formula or ⅛ Rule. Larger utilities have not been requesting the 45 Day Formula or ⅛ Rule.

Iowa: (Utilities Board, Dan Fritz, Utility Specialist, 515-725-7326, jim.kellenberg@iub.state.ia.us) Iowa uses lead/lag studies and the elements include interest expense on long-term debt, and do not include depreciation expense, deferred income tax expense or net income. The allowable elements have been established by practice; an example from the 2010 Interstate Power and Light rate case (RPU 2010-0001) is attached.

(2/24/15) Iowa requires a Lead-Lag study to support requests for cash working capital in rate base. There are two main versions. The two investor-owned utilities use Lead-Lag studies and the coops file simplified Lead-Lag studies. There are generally no other types of support filed for cash working capital in rate base. No utilities in Iowa ask for the 45 Day Formula or ⅛ Rule.

Kansas: (Corporation Commission, Utilities Division, Jeffrey McClanahan, Chief of Accounting and Financial Analysis, 785-271-3212) The Kansas Commission does not include depreciation expense, deferred income tax expense, or net income, and does include interest on long-term debt in lead/lag studies. This treatment is not set forth in a rule, statute or order. Lead/lag studies filed by a utility company in a rate case will be included in the docket schedules and available on the website.

(3/10/15) (Justin Grady, Chief of Accounting and Financial Analysis, 785-271-3164) The Kansas Commission requires utilities to supply a Lead-Lag study to support requests for cash working capital (CWC). When a Lead-Lag study is not supplied, CWC is set to zero. This treatment has been established by Commission order and longstanding practice. Very small tel-com companies are allowed to use the 45 Day Formula as it is set forth by the FCC. It's use by investor owned gas and electric utilities is categorically rejected. Black Hills Gas has requested recently to use the 45 Day Formula, unsuccessfully. In the most recent Black Hills rate case, Docket No. 14-BHCG-502-RTS, KCC Senior Auditor Andria N. Finger cited the Greeley Gas Company's rate Application, 22 Docket No. l 70,588-U7, and United Cities Gas Company's rate Application, Docket No. 181,940-U8, in which the Commission accepted Staff's adjustments of zero CWC where the Company had chosen not to perform a lead-lag study. Staff has consistently applied this standard to sophisticated investor owned utilities. In the 1990 Greely Gas case, the Commission stated, "If a utility desires any movement away from a zero working capital position it must account for that movement with a detailed lead-lag study as this Commission has required for some time." 1

1 In the Greely Gas rate case, Order dated October 22, 1990, at page 14, the Commission stated, "The Commission finds that there are several deficiencies that are inherent in the 45-day methodology which the Commission believes are not appropriate for a major utility such as Greely. The only statistical validity that is inherent in the 45-day formula is simply the assumption that 45 days worth of operating expenses

(6/7/16) (Justin Grady, Chief of Accounting and Financial Analysis, 785-271-3164) The Commission still requires a lead-lag study for utilities seeking a cash working capital adjustment and the calculation includes interest on long-term debt. An example of this treatment can be found in Section 6, page 2 of 6 in the Kansas City Power and Light rate case, Docket No. 15-KCPE-116-RTS.

Louisiana: (PSC, Brian McManus, Economist, Division of Economics and Rates Analysis, 225-342-2720) Louisiana uses the "rule of 8" rather than lead/lag studies for calculating CWC.
(2/24/15) Brian McMannus confirms that Louisiana uses the 45 Day Formula or ⅛ Rule.

Minnesota: (PUC, Jerry Dasinger, 651-201-2235) Practice has established, from the 1980's, the items included in lead/lag studies. Utilities now file studies as expected by the commission and generally contest only the number of days used. An example is the lead/lag study filed by Northern States (Xcel) in Docket No. E002/GR-10-971. Depreciation expense, deferred income tax, net income and interest expense are not included in the filed study.
(3/ /15) No response from MPUC.

Missouri: (PSC, Robert Schallenberg, Director, Audits, Accounting and Financial Analysis Department, 573-751-7162 bob.schallenberg@psc.mo.gov) Interest expense on long-term debt is included in lead/lag studies. Net income, depreciation and deferred income tax expenses are not included. The makeup of lead/lag studies was established in the early eighties when they replaced the 45 day rule. Elements included in the studies are not often challenged.
(2/24/15) Lead-Lag studies are used as a matter of practice, not required by specific rule. Missouri utilities have adjusted to using Lead-Lag studies and often simply update them to reflect changes. No utilities use the 45 Day Formula or ⅛ Rule in Missouri and none have requested to in over a decade.

Montana: (PSC, Eric Eck, Chief, Revenue Requirement Bureau, 406-444-6183) Depreciation and deferred income tax expenses are not included in lead/lag studies; nor is net income. Interest expense on long-term debt is included in lead/lag studies. The Commission has established the elements allowed in cash working capital calculations by practice, and this treatment is demonstrated in docket number 90.6.39, Order 5484K, finding numbers 74-84.
(3/10/15) Montana does require a Lead-Lag study as support for cash working capital requests. This treatment is based on practice. The Commission does not allow other support for cash working capital requests in rate base. The 45 Day Formula or ⅛ Rule is not accepted and not asked for in Montana.

are the appropriate amount for cash working capital, and in the state of Kansas where property taxes are paid substantially in arrears this impacts the 45-day approach greatly thus negating its validity and usefulness. If a utility desires any movement away from a zero working capital position it must account for that movement with a detailed lead-lag study as this Commission has required for some time."

Nebraska: (Public Service Commission, Laura Demman, Director and Legal Council, Natural Gas Department, NPSC, 402-471-3101) Electric customers in Nebraska are served entirely by consumer-owned electric utilities. For gas utilities, Nebraska uses a lead lag study if a company requests cash working capital. Depreciation expense, deferred income tax expense, net income and interest on long-term debt are all excluded. An example of this treatment can be found in the August 17, 2010 order in the Black Hills General Rate Case NG-0061.

(3/3/15) PSC, Angela Melton, Director and Legal Council, Natural Gas Department, NPSC, 402-471-3101) A company asking for cash working capital must submit a Lead-Lag study. This practice is not codified in a rule and was likely established by order. Other types of support are not an issue. The 45 Day Formula or ⅛ Rule is not used or requested in Nebraska.

Nevada: Nevada excludes depreciation expense, deferred taxes expense and net income but includes interest expense on long-term debt. NVE files all of its lead lag studies using this approach.

New Mexico: (Public Regulation Commission, Charles Gunter, Accounting Bureau Chief, Economist, 505-827-6977) New Mexico rules allow the use of lead/lag studies (NMAC, title 17/17.009.0530). The items considered in lead/lag studies do not include depreciation expense, deferred taxes expense, net income or interest expense on long-term debt. The items or accounts used are limited to the items/accounts included in cash working capital, such as fuel inventories, materials and supplies, prepayments and deferred charges.

(3/3/15) Rule 530 specifically allows for the use of a Lead-Lag study. In practice, larger utilities support requests for cash working capital with a Lead-Lag study. Smaller utilities may use the 45 Day Formula or ⅛ Rule. None of the larger utilities have asked to use the 45 Day Formula or ⅛ Rule.

North Dakota: (PSC, Mike Diller, Director of Accounting, 701-328-4079) None of the four items in question in this survey are included in the CWC Lead/Lag studies done in North Dakota for Northern States Power (Xcel) and Otter Tail Power companies. Depreciation is excluded because it is considered a non-cash item; deferred taxes are taken care of in the tax calculations; interest on long-term debt is accounted for in the cost of capital calculation; and net income is a function of revenues minus expenses and the components have already been considered. This treatment has been established by practice and is demonstrated in Xcel's most recent rate case, PU-10-657. North Dakota's other electric utility, Montana Dakota Utility quit filing lead/lag studies over 10 years ago.

(3/3/15) North Dakota regulations do not require Lead-Lag studies and the Commission would consider any method presented. However, the established practice is to use Lead-Lag studies. One of North Dakota's utilities does not request cash working capital in rate base. The other two use Lead-Lag studies. The 45 Day Formula or ⅛ Rule has not been used in North Dakota in the last 15 to 20 years, and no utilities request its use.

Oklahoma: Since the 1991 ONG rate case, Cause No. PUD 91-1190, Oklahoma has consistently excluded depreciation expense, deferred tax expense and net income from lead-lag analysis and has consistently included interest expense on long-term debt.

(3/13/15) (Oklahoma Corporation Commission, Bob Thompson, 405-521-6875)

Oregon: (PUC, Judy Johnson, Mgr. Rates and Tariffs, 503-378-6636; Deborah Garcia, 503-378-6688) Deborah Garcia reports that for electric utilities (PacifiCorp) follows the Utah approach for excluding non-cash items, such as depreciation, deferred tax and net income. (Note: these items are all excluded in Utah). Oregon considers this issue on a case-by-case basis; its treatment is not based on statute or rule. Judy Johnson reports that for its gas utilities, including Avista Utilities, Cascade and Northwest natural Gas, Oregon does not use lead/lag studies and discourages requests for cash working capital in general. Recent requests for cash working capital from gas utilities have been denied. This treatment is established by practice and not codified in rule or statute.

(3/3/15) (PUC, Judy Johnson, Mgr. Rates and Tariffs, 503-378-6636) The Oregon Commission requires utilities to supply Lead-Lag studies to support requests for cash working capital as a matter of policy. Any requests for another approach are met by quite a bit of testimony from Staff supporting Lead-Lag studies as the most accurate method. The Commission is reluctant to provide cash working capital to gas utilities and typically never grants any requests for cash working capital however supported. Avista (a gas utility) tried to use another type of study as support for cash working capital (not the 45 Day Formula or ⅛ Rule) and was unsuccessful. Electric utilities are allowed cash working capital and use Lead-Lag studies exclusively. No companies use or have asked to use the 45 Day Formula or ⅛ Rule.

South Dakota: (PUC, Dave Jacobson, Analyst, 605-773-3201) Lead/lag studies are used in South Dakota. Interest on long-term debt is included and its lead/lag days are calculated. Depreciation expense and deferred income tax expense are included, but at zero days (no dollar days). Net income is excluded. An example of this treatment can be seen in a recent Xcel rate case: SD EL09-009, Exhibit RLK-1, Schedule 1.

(3/3/15) (Eric Paulson, Utility Analyst, 605-773-6347) South Dakota does not require a Lead-Lag study by rule and companies are not restricted from filing other support. However, there are orders going back approximately 40 years that deny use of methods other than a Lead-Lag study. No investor owned utility in South Dakota has attempted to use the 45 Day Formula or ⅛ Rule since the late 1970's.

Texas: Texas ratemaking rules excludes non-cash items from the lead lag calculations. The Texas list of non-cash items includes depreciation, income, deferred taxes and interest expense. See §25.231(c)(2)(B).

(3/12/15) The Texas Public Utility Commission rules require larger electric utilities to use of a lead-lag study to support a request for cash working capital, including requests of zero. If the electric utility does not file a lead lag study or the lead-lag study is determined to be unreliable, an amount of cash working capital equal to negative one-eighth of operations and maintenance expense including fuel and purchased power is presumed to be the reasonable level of cash working capital. For small electric cooperatives and utilities that purchase 100% or their power requirements, one-eighth operation and maintenance expenses excluding taxes and depreciation is considered a reasonable allowance for cash working capital.

(3/3/15) (Texas Railroad Commission, Mark Evarts, Director, Market Oversight Section, Oversight and Safety Division (512) 427-9057) The Railroad Commission prefers Gas utilities in Texas to use of a Lead-Lag study to determine working capital. Large and medium size utilities all file Lead-Lag studies. The commission generally follows the guidance set forth in its _Natural Gas Rate Review Handbook_ which allows a utility which, "does not have the means to perform or to hire a consultant to perform a Lead-Lag study," to use a version of the 45 Day Formula or ⅛ Rule[2]. In practice, only very small utilities seek this treatment. Even with these very small utilities, Commission staff usually recommends using zero for cash working capital instead of the positive number that would be produced with the 45 Day Formula or the negative numbers typically produced by the Lead-Lag studies filed by the larger gas utilities in Texas.

Utah: (PSC, Rebecca Wilson, Executive Staff Director, 801-530-6707) Utah has a long-standing policy of excluding non-cash items from lead lag studies. These items include depreciation, deferred taxes and common equity. Interest expense was also excluded in the past but recently Staff has recommended in two settled cases that interest expense should be included in the calculations.

(3/3/15) Utah requires Lead-Lag studies as a matter of policy to support requests for cash working capital in rate base. Out of date Lead-Lag studies are sometimes filed and the Commission may request they be updated for the next rate case. Ms. Wilson is not aware of any requests to use the 45 Day Formula or ⅛ Rule.

Washington: (Washington Utilities and Transportation Commission, Roland Martin, Regulatory Analyst, 360-664-1304) Washington uses the “balance sheet” approach and does not use lead/lag studies.

(3/12/15) The Commission does not allow methods other than the balance sheet approach as support for cash working capital requests. The 45 Day Formula or ⅛ Rule is not considered because it cannot produce a negative amount. The Commission has been ask to consider accepting Lead-Lag studies; it has not been ask for the 45 Day Formula or ⅛ Rule.

Wyoming: (PSC, Marci Norby, Senior Rate Analyst, 307-777-5720) Wyoming does use lead/lag studies for larger utilities. Small companies which cannot afford lead/lag studies are allowed to use the 'rule of 8' (⅛th of O&M). For large utilities, lead-lag studies do not include depreciation expense, deferred taxes expense or net income and some utilities do include interest on long-term debt. Examples include the Questar Gas 2010 and Rocky Mountain Power 2007 lead lag studies which are attached.

(3/3/15) Larger utilities use Lead-Lag studies. Small utilities can use the 45 Day Formula or ⅛ Rule or a variation (e.g. 1/8th O&M and 1/12th commodities). This treatment is a matter of policy and not rule. A utility can propose whatever they like, but must be prepared to support it or it will be thrown out.

2 _Natural Gas Rate Review Handbook_ Chapter III (1)(E)(2), p18, provides for 45 days or 12.5 percent of operating expense, excluding cost of gas purchased, depreciation and taxes, plus the 13-month average amount of materials and supplies and the average prepayments.